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, 2013
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)

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

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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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 28, 2013, was $43.1 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 January 31, 2014, is shown below:

Title of Class	**Number of Shares Outstanding**
Common Stock, par value $0.10 per share	503,767,298

Documents Incorporated By Reference

Portions of the Proxy Statement for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 13, 2014 (to be filed with the Securities and Exchange Commission prior to April 3, 2014), are incorporated by reference into Part III of this Form 10-K.

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PART I

Items 1 and 2. Business and Properties

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.

GENERAL

Anadarko Petroleum Corporation is among the world's largest independent exploration and production companies, with approximately 2.8 billion barrels of oil equivalent (BOE) of proved reserves at December 31, 2013. 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 aimed at delivering long-term value to stakeholders by combining a large inventory of development opportunities in the U.S. onshore with high-potential worldwide offshore exploration and development activities.

Anadarko's asset portfolio includes U.S. onshore resource plays in the Rocky Mountains area, the southern United States, the Appalachian basin, and Alaska. The Company is also among the largest independent producers in the deepwater Gulf of Mexico, and has production and exploration activities worldwide, including activities in Algeria, Mozambique, Ghana, China, Brazil, Kenya, Côte d'Ivoire, Liberia, Sierra Leone, New Zealand, Colombia, South Africa, and other countries.

Anadarko is committed to producing energy in a manner that protects the environment and public health. Anadarko's focus is to deliver resources to the world while upholding the Company's core values of integrity and trust, servant leadership, people and passion, commercial focus, and open communication in all business activities.

Anadarko's business segments are managed separately due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are as follows:

Oil and gas exploration and production—This segment explores for and produces natural gas, crude oil, condensate, and natural gas liquids (NGLs), and plans for the development and operation of the Company's liquefied natural gas (LNG) project.

Midstream—This segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production. The Company owns and operates gathering, processing, treating, and transportation systems in the United States for natural gas, crude oil, and NGLs.

Marketing—This segment sells much of Anadarko's production, as well as third-party purchased volumes. The Company actively markets oil, natural gas, and NGLs in the United States; oil from Algeria, China, and Ghana; and anticipated LNG production from Mozambique.

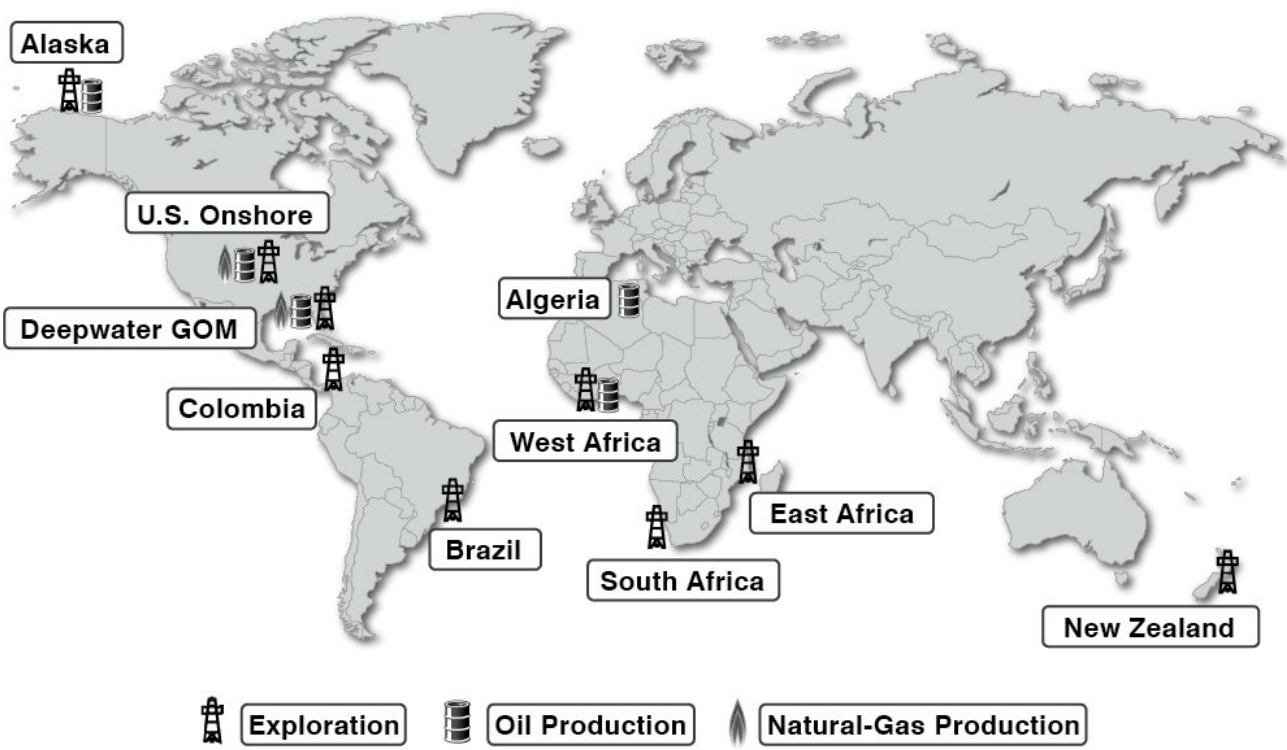
Unless the context otherwise requires, the terms "Anadarko" or "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company's corporate headquarters is located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046, and its telephone number is (832) 636-1000.

Available Information 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, and other reports and filings with the Securities and Exchange Commission (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 www.anadarko.com/Investor/Pages/SECFilings.aspx. 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 report, or any other filing, please contact Anadarko Petroleum Corporation, Investor Relations, P.O. Box 1330, Houston, Texas 77251-1330 or call (855) 820-6605, send an email to investor@anadarko.com, or submit a request using the Request Corporate Materials option under the Investor Relations tab on the Company's website at www.anadarko.com.

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 an internet site (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, like Anadarko, that file electronically with the SEC.

OIL AND GAS PROPERTIES AND ACTIVITIES

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



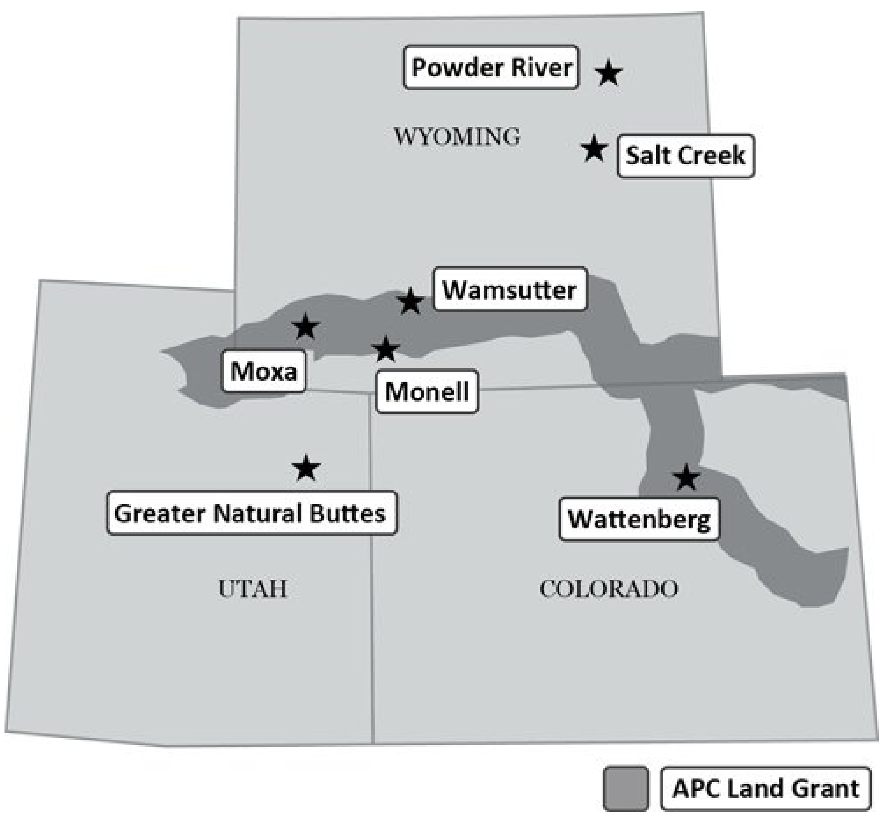
United States

Overview Anadarko's U.S. operations include oil and natural-gas exploration and production onshore in the Lower 48 states, the deepwater Gulf of Mexico, and onshore Alaska. The Company's U.S. operations accounted for 89% of total sales volumes during 2013 and 90% of total proved reserves at year-end 2013.

Rocky Mountains Region Anadarko's Rocky Mountains Region (Rockies) properties include oil and natural-gas plays located in Colorado, Utah, and Wyoming. The Company focused its 2013 capital investments in areas that offer high liquids yields (liquids-rich areas), which resulted in significant growth in oil production. Anadarko operates approximately 13,200 wells and owns an interest in approximately 9,500 nonoperated wells in the Rockies. Anadarko operates fractured-carbonate/shale reservoirs, tight-gas assets, coalbed-methane (CBM) natural-gas assets, and enhanced oil recovery (EOR) projects within the region. The Company also has fee ownership of mineral rights under approximately eight million acres that pass through Colorado, Wyoming, and into Utah (known as the Land Grant). Management considers the Land Grant a significant competitive advantage for Anadarko as it enhances the Company's economic returns from production on Land Grant acreage, offers drilling opportunities for the Company without expiration, and allows the Company to capture incremental royalty revenue from third-party activity on Land Grant acreage.

The Company believes its liquids-rich reservoirs, strong well performance, low development and operating costs, large expandable midstream infrastructure, and the competitive advantages provided by mineral ownership in the Land Grant each provide tangible benefits to the Company. Activities in the Rockies primarily focus on expanding existing fields to increase production and adding proved reserves through horizontal drilling, infill drilling, and down-spacing operations.

In 2013, total-year Rockies sales volumes increased 3% over 2012, with a 15%, or 14 thousand barrels of oil equivalent per day (MBOE/d), increase in liquids volumes. The Company drilled 707 wells and completed 658 wells in the Rockies during 2013. The Company plans to increase the number of horizontal wells drilled from 350 in 2013 to approximately 400 in 2014, with continued focus on liquids-rich areas.



Wattenberg The Wattenberg field is a liquids-rich area where Anadarko operates over 5,240 wells. The field contains the Niobrara and Codell naturally fractured formations that hold liquids and natural gas. During 2013, the Company's drilling program focused entirely on horizontal development, drilling 335 horizontal wells. Sales volumes in the Wattenberg field increased 21% compared to 2012, with a year-over-year 36% increase in oil volumes and 32% increase in total liquids volumes. Horizontal drilling results in the Wattenberg field have shown strong initial production rates with average liquids yields of approximately 67%. The Company has identified approximately 4,000 potential drilling locations in the Niobrara and Codell formations that are expected to provide substantial opportunity for Anadarko's continued activity. In 2014, the Company plans to employ 13 horizontal rigs in the Wattenberg field and expects wells drilled to increase as a result of the increased number of rigs operating in the area and from improved drilling efficiencies and cycle times.

In October 2013, Anadarko exchanged certain oil and gas properties in the Wattenberg field with a third party. Under the terms of the transaction, each party exchanged approximately 50,000 net acres. This exchange consolidated Anadarko's working interest and operated acreage positions in this core development area, while retaining the royalty benefit of the Company's Land Grant mineral ownership on approximately 21,000 acres of the lands conveyed to the third party. The trade increased Anadarko's production by 8,000 barrels of oil equivalent per day (BOE/d) since October 2013. Consolidating Anadarko's operating position is expected to provide significant value through more efficient development planning and infrastructure utilization. The Company also expects to improve operating efficiencies, reduce costs, and reduce impacts to local communities as a result of this exchange.

In September 2013, the Company shut in approximately 675 operated vertical wells in the Greater Wattenberg area in preparation for and during the flooding in Colorado. Due to damaged roads, bridges, railways, and other issues impacting the ability to move heavy equipment such as rigs and compression units, the Company experienced disruptions to its drilling, completion, and construction activities in the area. These disruptions have been resolved and the Company does not expect production volumes to be significantly affected in 2014.

Greater Natural Buttes The Greater Natural Buttes area in eastern Utah is one of the Company's major tight-gas assets. The Company utilizes both refrigeration and cryogenic processing facilities in this area to extract NGLs from the natural-gas stream.

The Company operates approximately 2,800 wells in the Greater Natural Buttes area, drilled 223 wells in 2013, and increased year-over-year sales volumes from the area by 2%. Anadarko identified more than 1,800 potential locations in the Wasatch/Mesaverde formations. Many of these locations are infill drilling opportunities focused on down-spacing from 40-acre well density to 10-acre well density.

Powder River Deep The Company drilled 14 horizontal wells in the Powder River basin during 2013 as part of a multi-objective horizontal exploration program targeting liquids-rich plays. Anadarko controls over 350,000 acres of deep rights within the Powder River basin.

Coalbed Methane Properties Anadarko operates approximately 2,200 CBM wells and owns an interest in approximately 4,200 nonoperated CBM wells in the Rockies, primarily located in the Powder River basin in Wyoming and the Helper and Clawson fields in Utah. Anadarko controls over 640,000 acres of shallow rights within the Powder River basin. CBM is natural gas that is generated and stored within coal seams. To produce CBM, water is extracted from the coal seam, resulting in reduced pressure and the release of natural gas, which flows to the wellhead. The Company expects to remain at a reduced CBM activity level in 2014 as a result of low natural-gas prices.

Salt Creek and Monell During 2013, the Company continued the development of its Rockies EOR assets at the Salt Creek and Monell fields in Wyoming. The Company's EOR operations use carbon dioxide (CO_2) to stimulate oil production from mature reservoirs after primary and water-flood recovery methods have been completed. Significant gains in production were achieved in this area due to the Company's ongoing development programs, with oil production rising 13% in 2013. In 2014, the Company plans to continue the development of these fields with additional facility expansion projects and a continued limited drilling program to enhance CO_2 flooding operations.

In 2012, the Company entered into a carried-interest arrangement where a third party agreed to fund $400 million of development costs in exchange for a 23% interest in the Company's EOR development at the Salt Creek field in Wyoming. At December 31, 2013, $375 million of the $400 million obligation had been funded.

Greater Green River Basin Anadarko operates over 1,400 wells in the Wamsutter and Moxa fields and carries a nonoperated position in 3,400 wells between the two fields. Much of this producing area is in the Land Grant, which improves the economics of projects in the area.

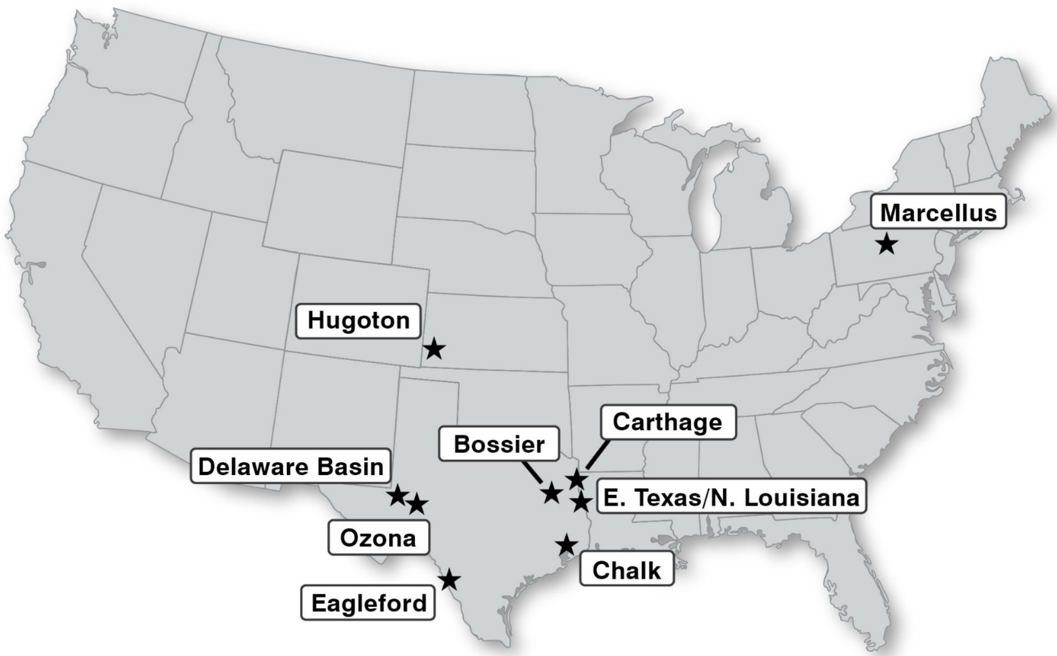
In 2013, Anadarko acquired additional wells, increased interest in existing wells, and increased acreage in the Company's core areas of this basin through the completion of a $310 million acquisition in the Moxa field. This acquisition resulted in a production increase of approximately 6,500 BOE/d, with significant additional value expected to be provided through decreased operating costs, maintenance performed to increase base production, and further infill drilling potential.

In January 2014, Anadarko sold its interest in the Pinedale/Jonah assets in Wyoming for $581 million.

Southern and Appalachia Region Anadarko's Southern and Appalachia Region properties are primarily located in Texas, Pennsylvania, Louisiana, and Kansas. Anadarko holds an interest in approximately 4.2 million gross acres throughout the Southern and Appalachia Region. The region includes the Eagleford shale in South Texas, the Marcellus shale in north-central Pennsylvania, the Delaware basin in West Texas, and the Haynesville shale in East Texas and Louisiana. Operations in these areas are focused on finding and developing both natural gas and liquids from shales, tight sands, and fractured-reservoir plays.

During 2013, the Company continued to focus on liquids-rich opportunities across the region by expanding drilling activity in the emerging Wolfcamp and other shale plays, while continuing its existing liquids-rich projects in the Eagleford, Delaware basin, and East Texas/North Louisiana plays. The Company has reduced costs and benefited from improved cycle-time efficiencies in both drilling and completion operations across all operating areas in the region.

In 2013, total-year sales volumes in the Southern and Appalachia Region increased 30% over 2012, with a 29% increase in liquids volumes. The Company drilled 593 operated horizontal wells and brought 533 wells online in 2013. The Company expects to drill approximately 665 horizontal wells in the Southern and Appalachia Region in 2014.



Eagleford The Eagleford shale performance continued to benefit from a carried-interest arrangement entered into in 2011 that conveyed 33.3% of the Company's Eagleford shale assets and the underlying Pearsall shale rights to a third party in exchange for the funding of $1.6 billion of Anadarko's development costs. The third party funded $444 million of the Company's development costs in 2013, which completed its funding commitment.

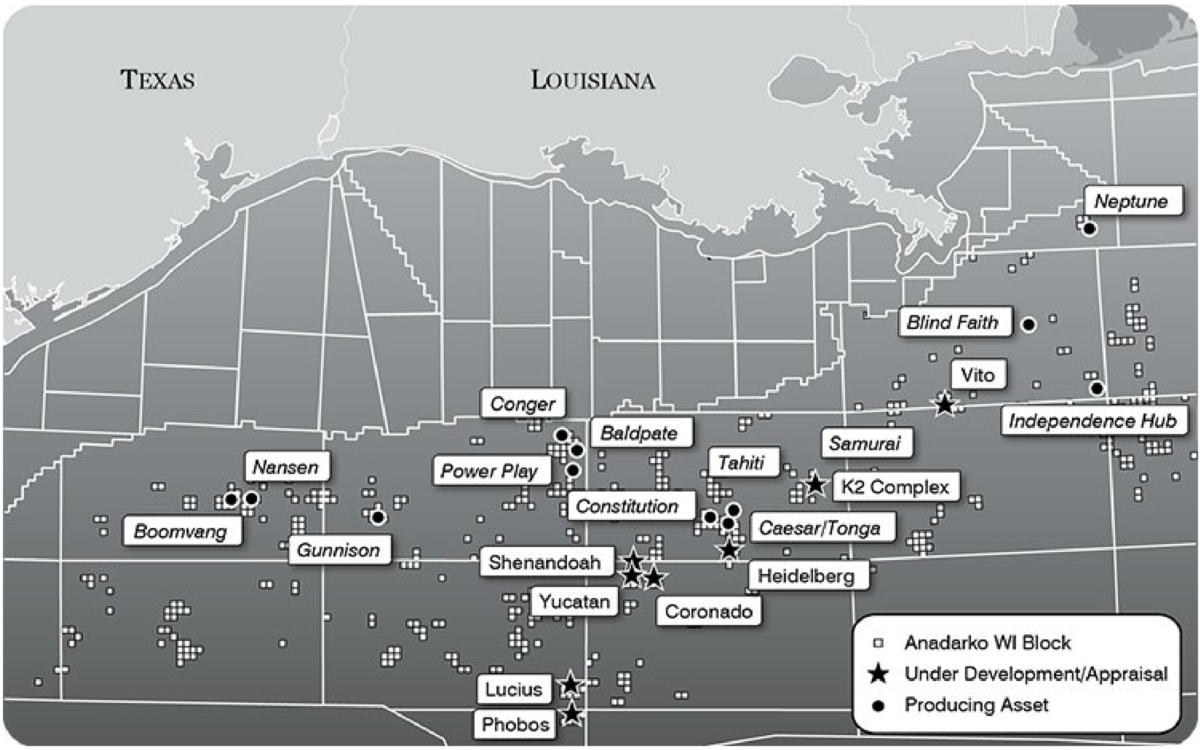
Anadarko currently holds 388,000 gross acres in this area. During 2013, the Company operated an average of nine rigs and spud 359 horizontal wells. The Company increased sales volumes by 46% year over year. During 2013, Anadarko also expanded its infield gathering-system capacity from 350 million cubic feet per day (MMcf/d) to approximately 600 MMcf/d with the completion of a new gas compression facility. In addition, three oil stabilization trains were added with an oil capacity of 75 thousand barrels per day (MBbls/d). Gas processing capacity was also expanded in 2013 by completion of the Company's new high-efficiency cryogenic gas plant that came online in June. This 200-MMcf/d Brasada natural-gas processing plant is capable of recovering approximately 30 MBbls/d of NGLs.

Delaware Basin Anadarko holds an interest in over 602,000 gross acres in the Delaware basin. Anadarko's 2013 drilling activity primarily targeted the liquids-rich Bone Spring formation, the Avalon shale, and the developing Wolfcamp shale play. In 2013, Anadarko spud 74 operated wells and participated in 36 nonoperated wells. Significant infrastructure was added, which increased NGLs sales volumes by 47% over 2012. The Company had two operated rigs drilling in the Bone Spring formation, three operated rigs drilling in the Avalon shale, and six operated rigs drilling in the Wolfcamp shale at year-end 2013.

East Texas/North Louisiana Anadarko increased its capital program in the East Texas Carthage area in 2013, targeting a liquids-rich area in the Haynesville shale. In 2013, Anadarko operated seven rigs and drilled 76 wells in the Haynesville and Cotton Valley formations. The Company increased sales volumes from the area by 40% year over year.

Marcellus In the Marcellus shale of the Appalachian basin, where the Company holds 773,000 gross acres, 61 operated horizontal wells were spud using a fleet average of three rigs during the year. Anadarko also participated in drilling an additional 51 nonoperated horizontal wells in 2013. The Company's production volumes in Marcellus continued to improve with sales volumes increasing 58% over 2012.

Gulf of Mexico In the Gulf of Mexico, Anadarko owns an average 63% working interest in 444 blocks. The Company operates six active floating platforms, holds interests in 29 producing fields, and is in the process of delineating and developing two additional fields. During 2013, the Company continued an active deepwater exploration and appraisal program in the Gulf of Mexico as it continues to take advantage of its existing infrastructure to accelerate development activities at reduced costs.



The following includes the significant development, exploration, and appraisal activity during 2013.

Development Anadarko continues to advance the Lucius project toward first oil in the second half of 2014. Fabrication was completed in 2013 on the production spar that will support the development. The spar was successfully towed, installed, and secured over Keathley Canyon Block 875. The subsea infrastructure is currently being installed with the 80-MBbls/d topside facilities on schedule for delivery in the first quarter of 2014. The Company has successfully finished the Phase 1 development drilling campaign and is now focusing its efforts on completion operations. In 2012, Anadarko entered into a carried-interest arrangement that requires a third-party partner to fund $556 million of capital costs in exchange for a 7.2% working interest in the Lucius development. The carry obligation is expected to cover the substantial majority of the Company's expected future capital costs through first production. At December 31, 2013, $416 million of the $556 million obligation had been funded and the remaining portion is expected to be funded during 2014. Following the transaction, the Company held a 27.8% working interest in the Lucius development.

Anadarko is also advancing the Heidelberg development with construction of the 80-MBbls/d spar progressing on schedule. The project was sanctioned during the second quarter of 2013. During the year, the Company entered into a carried-interest arrangement that requires a third-party partner to fund $860 million of capital costs in exchange for a 12.75% working interest in the development. The carry obligation is expected to cover the substantial majority of the Company's expected future capital costs through first production. At December 31, 2013, $119 million of the $860 million obligation had been funded. Following the transaction, Anadarko held a 31.5% working interest in Heidelberg. Development drilling is on schedule to begin in the first quarter of 2014 with first production anticipated in 2016.

At Marco Polo (100% working interest) in the K2 Complex, two wells were successfully sidetracked and completed during 2013. The A3 well came online at a sustainable net rate of 2,400 BOE/d and the A5 well came online at a sustainable net rate of 3,500 BOE/d. At Constitution (100% working interest), the Company executed a successful platform drilling program in 2013, where the A6 well was sidetracked, completed, and brought online. The next drilling programs for both of these oil-producing fields are expected to commence in the first quarter of 2014. At Ticonderoga (50% working interest), Anadarko drilled, completed, and brought online the GC 768-4 well, which is a tieback to the Constitution spar.

The Company successfully drilled and completed a fourth development well at Caesar/Tonga, which began producing in the first quarter of 2014. The Company purchased an additional 11.25% interest in Power Play during the year, bringing its total working interest to 56.25%. Anadarko also completed the transfer of its ownership in the Neptune spar to a third party at the end of 2013.

Exploration Three new discoveries were drilled in the Gulf of Mexico in 2013, including two in Walker Ridge and one in the Sigsbee Escarpment area.

In the Shenandoah basin in Walker Ridge, discoveries were successfully drilled at Coronado (35% working interest) and at Yucatan (15% working interest). The Coronado-1 discovery well encountered more than 400 net feet of oil pay in high-quality Lower Tertiary reservoirs. The Company increased its ownership position in the Coronado discovery from 15% to 35% and will assume operatorship following the drilling of a second appraisal well, which was spud in the fourth quarter of 2013. The Yucatan-1 discovery well, drilled approximately three miles south and syncline-separated from the Shenandoah-2 appraisal well, encountered more than 120 net feet of high-quality oil pay in Lower Tertiary-aged reservoirs.

The Phobos exploration well (30% working interest) was the first well drilled in the Sigsbee Escarpment area, approximately 11 miles south of the Company-operated Lucius field. The well spud in December 2012 and was determined to be successful in the second quarter of 2013. The well encountered approximately 250 net feet of high-quality oil pay in Lower Tertiary-aged reservoirs, trapped in a large, multi-block, four-way closure.

Appraisal Anadarko participated in drilling successful appraisal wells associated with three Gulf of Mexico discoveries: Shenandoah, Coronado, and Vito. The Company-operated Shenandoah-2 well (30% working interest) reached total depth in January 2013, encountering more than 1,000 net feet of oil pay in multiple high-quality Lower Tertiary reservoirs. Similar to the initial Shenandoah discovery, well log and pressure data from the Shenandoah-2 well indicated excellent-quality reservoir and fluid properties. The targeted pay sands were full of oil with no oil-water contact.

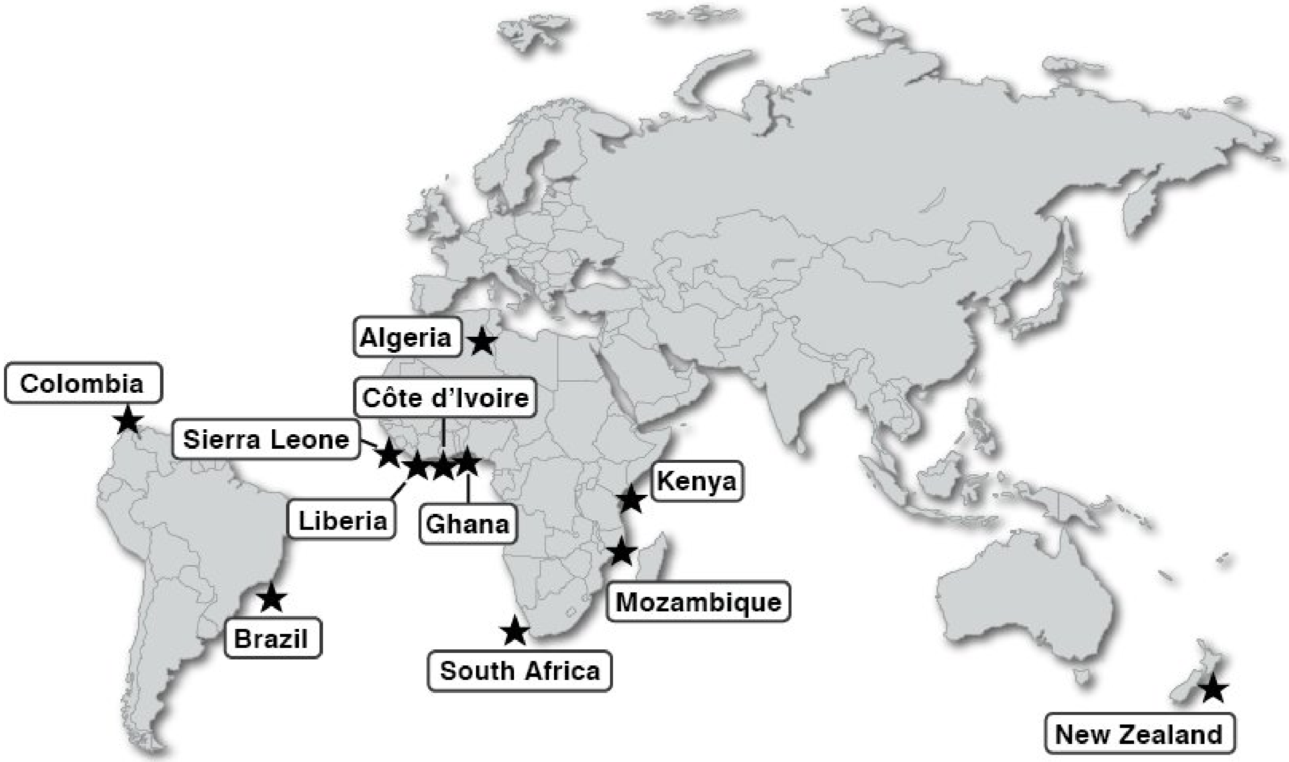
During the second quarter of 2013, the Company participated in the appraisal sidetrack at Coronado, which defined the down-dip extent of the accumulation discovered earlier in the year. At year end, the second appraisal well was drilling in Walker Ridge Block 143.

Another successful appraisal well was drilled at the Vito discovery (18.67% working interest) in Mississippi Canyon Block 984 and further defined the extent of the field.

Alaska Anadarko's oil production and development activity in Alaska is concentrated primarily on the North Slope. Infrastructure construction began during 2013 in preparation of the upcoming Alpine West development, a 15-to-20-well extension of the Alpine field, which is estimated to commence production in late 2015 or early 2016.

International

Overview Anadarko's international oil and natural-gas production and development operations are located in Mozambique, Algeria, Ghana, and China. The Company also has exploration acreage in Ghana, Mozambique, Brazil, Liberia, Sierra Leone, Kenya, Côte d'Ivoire, China, New Zealand, Colombia, South Africa, and other countries. International locations accounted for 11% of Anadarko's total sales volumes and 26% of sales revenues during 2013, and 10% of total proved reserves at year-end 2013. In 2014, the Company expects to drill 14 to 18 development wells and 15 to 18 exploration/appraisal wells in various international locations.



Mozambique Anadarko operates two blocks (one onshore and one offshore) totaling approximately 5.7 million gross acres.

Development During 2013, the Company made progress advancing the Rovuma Offshore Area 1 gas development project towards sanction. The Environmental Impact Assessment was completed including all necessary public consultations and the final report has been prepared for submittal. Site preparation and early infrastructure improvements at the Afungi Peninsula location have been initiated. The Company has completed front-end engineering and design (FEED) for the offshore gathering infrastructure and bid invitations have been issued. The FEED for the onshore liquefaction facilities is nearing completion and remains on schedule. The first LNG train is targeted to achieve first delivery in 2018.

In February 2014, the Company sold a 10% working interest in Rovuma Offshore Area 1 in Mozambique for $2.64 billion. Anadarko remains the operator of Rovuma Offshore Area 1 with a working interest of 26.5%.

Anadarko and its partners continue to make progress marketing LNG to be produced from Rovuma Offshore Area 1 in Mozambique. The partners have reached non-binding Heads of Agreements for long-term LNG sales to buyers in Asian markets covering approximately two-thirds of the first 5-million-tonne-per-annum train.

Exploration In 2013, the Company made additional discoveries in Mozambique at Espadarte and Orca. The Espadarte exploration well targeted an exploration play in the Miocene and the up-dip extent of the Oligocene-aged reservoirs found at the Golfinho-Atum field. The well encountered approximately 50 net feet of natural-gas pay in the Miocene reservoirs and 230 net feet of natural-gas pay in the Oligocene reservoirs. Pressure data indicate the Oligocene sands are in communication with the Golfinho-Atum reservoirs discovered in 2012, confirming the well as a northwest extension of the field. The Orca exploration well reached total depth during the first quarter of 2013 and encountered approximately 190 net feet of natural-gas pay in a single Paleocene reservoir. The Manta-1 exploration well, which had an exploration target in the Miocene and an appraisal target in the Oligocene-aged reservoirs from the Golfinho field, also tested the northernmost extent of the Orca discovery. The Manta-1 well encountered approximately 360 net feet of natural-gas pay in the Oligocene, and 115 net feet of pay in the Paleocene. A two-well appraisal program for the Orca discovery is planned for 2014. The Atum-3 appraisal well encountered approximately 230 net feet of natural-gas pay and established the gas-water contact for the Golfinho-Atum field. In addition, two successful Golfinho appraisal wells were drilled in 2013.

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 between Anadarko, two other parties, and Sonatrach, the national oil and gas company of Algeria. The Company is responsible for 24.5% of the development and production costs for these blocks. The Company produces oil through the Hassi Berkine South and Ourhoud central processing facilities in Block 404 and oil, condensate, and NGLs through the El Merk central processing facility in Block 208. Gross oil production through these facilities averaged more than 300 MBbls/d throughout 2013. Initial production from El Merk in Block 208 was achieved in the first quarter of 2013, and production from the facility increased throughout the year as two 65-MBbls/d oil trains and a natural-gas processing and NGLs extraction train were completed and brought online. Final commissioning of the NGLs extraction train is ongoing and will be completed in the first quarter of 2014. The Company drilled 10 development wells in 2013 and expects to drill 10 to 12 additional development wells in 2014.

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

During 2013, the Company and its partners completed four additional wells in the Jubilee field (24% nonoperated unit interest), which spans both the West Cape Three Points Block and the Deepwater Tano Block. The Company and its partners are expanding the natural-gas handling capacity on the floating production, storage, and offloading vessel (FPSO) to allow for increased oil production, and exited the year with a gross oil production rate of 100 MBbls/d in the Jubilee field. The Company and its partners also commenced a study to evaluate options to further expand the oil throughput capacity of the FPSO.

The Akasa 2A appraisal well was drilled in the West Cape Three Points Block (31% nonoperated working interest) and development options are being evaluated to maximize the value from the Mahogany, Teak, and Akasa discoveries.

In May 2013, the Government of Ghana approved the Plan of Development for the Tweneboa/Enyenra/Ntomme (TEN) complex (19% nonoperated working interest) and the project was sanctioned by the Company and its partners. Major facility construction contracts have been awarded for the development, which will utilize an 80-MBbls/d FPSO for production from subsea wells. The Company expects first production in 2016. The Company participated in three exploration and appraisal wells in the Deepwater Tano block in 2013.

China Anadarko's production and development activities in China are located offshore in Bohai Bay. During 2013, the Company and its partners drilled and brought online 12 new wells. A development plan for the next major field expansion is being created and final governmental approval and project sanction is expected to be completed in 2014. Consistent with the terms of the petroleum contract, the Company transferred operatorship of the Bohai Bay development to CNOOC China Limited effective January 1, 2013. The Company maintains an average working interest of approximately 35%.

The Liwan 21-1-1 exploration well (50% working interest) in the South China Sea spud in August 2012 and was suspended after setting surface casing due to rig commitments and weather considerations. Drilling resumed on the well during the fourth quarter of 2013. The well encountered high-quality sands, but was determined to be non-commercial. The Company's capital spending on the well was fully carried by a third party.

In February 2014, the Company entered into an agreement to sell its oil and gas properties in China for $1.075 billion. The transaction is expected to close later in 2014 and is subject to preferential rights, regulatory approvals, and other customary closing conditions.

Brazil Anadarko holds exploration interests in approximately 350,000 gross acres in three offshore blocks located in the Campos basin. In early 2013, a drillstem test was completed at the Itaipu-1 (33% working interest) discovery well in BM-C-32. The well flowed at rates up to 5,600 Bbls/d. A successful appraisal of the Itaipu discovery was also drilled during the year. The Company-operated Wahoo-5 (30% working interest) appraisal well in BM-C-30 was drilled in the eastern flank of the Wahoo structure and encountered more than 200 net feet of high-quality pay in a pre-salt reservoir, with a total hydrocarbon column now established at 460 feet. Unitization discussions continue at Itaipu.

Liberia The Company operates Block 10 (80% working interest) and Block 15 (48% working interest) in the offshore Liberian basin totaling approximately 1.3 million exploration acres. Multiple Cretaceous stratigraphic prospects, similar to the Jubilee Mahogany fan, have been identified on these blocks. Block 10 exploration drilling is planned for 2014.

Sierra Leone Anadarko owns and operates a 55% working interest in offshore Block SL-07B-11, which encompasses approximately 1.3 million gross acres. Multiple Upper Cretaceous fan-type prospects have been identified in the lightly explored Liberian basin. Data from the previously drilled exploration wells is being evaluated to determine future drilling plans.

Kenya Anadarko owns and operates a 45% working interest in five offshore deepwater blocks, encompassing approximately 5.6 million gross acres. The Company drilled two exploration wells in 2013. The Kubwa well in Block L-7 encountered non-commercial oil shows in reservoir-quality sands. The Kiboko well in Block L-11 encountered well-developed reservoir sands with low permeability and also encountered indications of a working petroleum system. The results are being integrated into the geologic model with plans for additional exploration drilling in 2014.

Côte d'Ivoire Anadarko owns working interests in five offshore blocks totaling approximately 1.4 million acres, including Blocks CI-515 and CI-516 with a 45% operated working interest and Block CI-103 with a 55% nonoperated working interest. Two additional blocks, CI-528 and CI-529 (90% working interest, operated), were acquired during 2013. The Calao exploration well was drilled on Block CI-103 in early 2013 and encountered non-commercial volumes of hydrocarbons. A combination exploration and down-dip appraisal of the 2012 Paon discovery in Block CI-103 was drilled in the fourth quarter of 2013. No hydrocarbons were encountered in the exploration targets, but pressure data obtained in the Paon appraisal well indicates a potential oil-water contact in the reservoir found by the Paon discovery well. The potential for a commercial accumulation at Paon will be further tested in 2014 by the Paon 3A appraisal well.

New Zealand Anadarko operates approximately 10 million gross exploration acres in four offshore blocks, with a 48% working interest in the Taranaki basin block, a 45% working interest in the Canterbury basin block, and a 100% working interest in two Pegasus basin blocks. In 2011, a 3D seismic survey of approximately 700 square miles was completed on the Taranaki block and a 2D seismic survey of approximately 2,400 miles was acquired over the Canterbury block. The Romney-1 exploration well on the Taranaki block reached its total depth objective during the first quarter of 2014, and the reservoir was water-bearing. An exploration well is expected to be drilled in the Canterbury basin in 2014.

Colombia Anadarko owns and operates exploration acreage in six offshore blocks, totaling approximately 7.8 million acres. The Company owns a 100% working interest in the COL 2 Block and a 50% working interest in the remaining blocks. Existing 2D and 3D seismic data has been reprocessed and combined with a newly acquired 2,100-square mile 3D survey, which was completed in 2013. The seismic data is being interpreted to develop a multi-well drilling program planned to begin in late 2014 or early 2015.

South Africa The Company operates offshore Block 5/6/7 (80% working interest), which covers over 23 million acres. In 2013, a 3,800-mile 2D seismic program and a high resolution sea floor survey were completed. This data is being interpreted and mapped to better understand the basin geology and plan a 3D seismic program.

Other Anadarko also has exploration projects in other overseas, new-venture areas including Guyana, Morocco, and Tunisia.

Proved Reserves

Estimates of proved reserves volumes owned at year end, net of third-party royalty interests, are presented in billion cubic feet (Bcf), at a pressure base of 14.73 pounds per square inch for natural gas and in millions of barrels (MMBbls) for oil, condensate, and NGLs. Total volumes are presented in millions of barrels of oil equivalent (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.

Disclosures by geographic area include the United States and International. The International geographic area consists of proved reserves located in Algeria, Ghana, and China, which by country and in total represents less than 15% of the Company's total proved reserves.

Summary of Proved Reserves

	Natural Gas (Bcf)	Oil and Condensate (MMBbls)	NGLs (MMBbls)	Total (MMBOE)
December 31, 2013				
Proved				
Developed				
United States	**7,120**	**347**	**268**	**1,801**
International	**—**	**202**	**—**	**202**
Undeveloped				
United States	**2,085**	**245**	**127**	**720**
International	**—**	**57**	**12**	**69**
Total proved	**9,205**	**851**	**407**	**2,792**
December 31, 2012				
Proved				
Developed				
United States	6,445	318	283	1,675
International	—	208	—	208
Undeveloped				
United States	1,884	193	110	617
International	—	48	12	60
Total proved	8,329	767	405	2,560
December 31, 2011				
Proved				
Developed				
United States	6,113	352	267	1,638
International	—	173	—	173
Undeveloped				
United States	2,252	184	94	653
International	—	62	13	75
Total proved	8,365	771	374	2,539

The Company's year-end 2013 proved reserves product mix was comparable to the last two years with 55% natural gas, 30% oil and condensate, and 15% NGLs.

The Company's estimates of proved developed reserves, proved undeveloped reserves (PUDs), and total proved reserves at December 31, 2013, 2012, and 2011, and changes in proved reserves during the last three years are presented in the *Supplemental Information on Oil and Gas Exploration and Production Activities (Supplemental Information)* under Item 8 of this Form 10-K.

The Company has not yet filed information with a federal authority or agency with respect to its estimated total proved reserves at December 31, 2013. 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.

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 *Operating Results* and *Critical Accounting Estimates* under Item 7 of this Form 10-K for additional information on the Company's proved reserves.

Changes in PUDs Changes to PUDs occurring during 2013 are summarized in the table below. Revisions of prior estimates include updates to prior PUDs, the addition of new PUDs associated with current development plans, the transfer of PUDs to unproved categories due to development plan changes, and the impact of changes in economic conditions, including changes in commodity prices. PUD revisions reflect Anadarko's ongoing evaluation of its asset portfolio and current-year changes to development plans. 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, 2013	**677**
Revisions of prior estimates	**197**
Extensions, discoveries, and other additions	**109**
Conversion to developed	**(183)**
Sales	**(11)**
PUDs at December 31, 2013	**789**

Revisions In 2013, PUD reserves revisions of 197 MMBOE were primarily related to successful infill drilling in large onshore areas such as Wattenberg and Greater Natural Buttes in the Rockies and the Eagleford shale in the Southern and Appalachia Region, partially offset by decreases due to development plan updates and lower ethane prices in the Rockies.

Additions During 2013, Anadarko added 109 MMBOE of PUD reserves through extensions, discoveries, and other additions, primarily as a result of successful drilling at Heidelberg and Caesar/Tonga in the Gulf of Mexico and in the Marcellus shale in the Southern and Appalachia Region.

Conversions In 2013, the Company converted 183 MMBOE, or 27% of total year-end 2012 PUDs, to developed status. Approximately 85% of PUD conversions occurred in U.S. onshore assets, 11% in international assets, and the remaining 4% in Gulf of Mexico assets.

The majority of the U.S. onshore PUD conversions occurred as a result of development activities, which included 107 MMBOE in the Rockies and 48 MMBOE in the Southern and Appalachia Region. International PUD conversions of 20 MMBOE were primarily associated with ongoing development activities in the Company's African assets. The remaining PUD conversions were associated with development projects in various Gulf of Mexico fields and Alaska.

Anadarko spent $1.0 billion to develop PUDs in 2013, of which approximately 70% related to domestic development programs in the Rockies and the Southern and Appalachia Regions, 25% related to development of international projects, and the remaining 5% related to Alaska and Gulf of Mexico development projects.

In 2012, the Company converted 171 MMBOE, or 23% of the total year-end 2011 PUDs, to developed status. Approximately 79% of PUD conversions occurred in U.S. onshore assets, 15% in international assets, and the remaining 6% in Gulf of Mexico assets. Anadarko spent $1.0 billion on PUD development in 2012, of which approximately 69% related to domestic development programs in the Rockies and the Southern and Appalachia Regions, 28% related to development of international projects, and the remaining 3% related to Alaska and Gulf of Mexico development projects.

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 such as EOR, arctic development, deepwater development, and international programs may take longer. All of the Company's U.S. onshore PUDs at December 31, 2013, were scheduled to be developed within five years, with the exception of the Salt Creek EOR project, the annual development of which is limited by CO_2 supply.

At December 31, 2013, the Company had 89 MMBOE of pre-2009 PUDs that remained undeveloped. Approximately 31% of these PUDs are associated with the El Merk development project and are being developed according to an Algerian government-approved plan. Construction of the El Merk central processing facility has been completed and 97 of the 119 wells in the approved Reservoir Development Plan have been drilled. Anadarko and its partners achieved initial oil production in 2013 as two oil trains and a natural-gas processing and NGLs extraction train were completed and brought online during the year. Final commissioning of the NGLs extraction train is ongoing and will be completed in the first quarter of 2014.

Another 24% of the Company's pre-2009 PUDs are associated with the Salt Creek EOR single-development project located in the Rockies. Since 2003, Anadarko has invested an average of $79 million per year to develop various phases of the Salt Creek EOR project and will continue significant spending levels in the future to complete the development.

All remaining pre-2009 PUDs are associated with various Gulf of Mexico opportunities where longer development times are a result of various delays associated with operating in a deepwater environment, including the impacts of the deepwater drilling moratorium.

Technologies Used in Proved Reserves Estimation The Company's 2013 proved reserves additions were based on estimates generated through the integration of relevant geological, engineering, and production data, utilizing 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 utilized 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-Reserves Administration and the Corporate Reserves Manager manage the CRG and report 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 of Directors 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 27 years of experience in the oil and gas industry, including over 13 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 Evaluation Engineers and the Society of Petroleum Engineers, where he has been a member for over 27 years. 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 its internal estimates of proved reserves and future net cash flows at December 31, 2013. 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 was a limited review of Anadarko's procedures and methods and does 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 18 fields that included major assets in the United States and Africa, and encompassed approximately 88% of the Company's estimates of proved reserves and associated future net cash flows at December 31, 2013. 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 Company's sales volumes were 285 MMBOE for 2013, 268 MMBOE for 2012, and 248 MMBOE for 2011. Production costs are costs to operate and maintain the Company's wells and related equipment and include the cost of labor, well service and repair, location maintenance, power and fuel, transportation, other taxes, and production-related general and administrative 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. Information on major customers is contained in *Note 21—Segment Information* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. 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]				
	Natural Gas (Bcf)	Oil and Condensate (MMBbls)	NGLs (MMBbls)	Barrels of Oil Equivalent (MMBOE)	Natural Gas (Per Mcf)	Oil and Condensate (Per Bbl)	NGLs (Per Bbl)	Average Production Costs [2] (Per BOE)
2013								
United States								
Greater Natural Buttes	**168**	**1**	**4**	**33**	**$ 3.12**	**$ 87.46**	**$ 41.79**	**$ 9.59**
Wattenberg	**102**	**16**	**6**	**40**	**3.75**	**94.27**	**41.75**	**8.55**
Other United States	**698**	**41**	**23**	**179**	**3.56**	**98.38**	**36.14**	**8.72**
Total United States	**968**	**58**	**33**	**252**	**3.50**	**97.02**	**37.97**	**8.81**
International	**—**	**33**	**—**	**33**	**—**	**109.15**	**—**	**9.96**
Total	**968**	**91**	**33**	**285**	**3.50**	**101.41**	**37.97**	**8.94**
2012								
United States								
Greater Natural Buttes	163	1	5	33	$ 2.26	$ 81.34	$ 40.43	$ 8.75
Wattenberg	95	12	5	33	3.00	92.16	40.72	8.05
Other United States	655	42	20	171	2.73	99.36	40.37	8.76
Total United States	913	55	30	237	2.68	97.46	40.44	8.66
International	—	31	—	31	—	111.11	—	10.89
Total	913	86	30	268	2.68	102.35	40.44	8.92
2011								
United States								
Greater Natural Buttes	135	1	4	27	$ 3.58	$ 84.13	$ 51.50	$ 9.48
Wattenberg	79	9	5	27	4.17	91.91	53.85	7.58
Other United States	638	38	18	163	3.90	99.28	54.55	9.80
Total United States	852	48	27	217	3.87	97.70	53.95	9.50
International	—	31	—	31	—	109.20	—	9.98
Total	852	79	27	248	3.87	102.24	53.95	9.55

Bcf—billion cubic feet
Mcf—thousand cubic feet
Bbl—barrel
(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.

Delivery Commitments

The Company sells crude oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. At December 31, 2013, Anadarko was contractually committed to deliver approximately 950 Bcf of natural gas to various customers in the United States through 2031. These contracts have various expiration dates with approximately 42% of the Company's current commitment to be delivered in 2014, and 68% by 2018. At December 31, 2013, Anadarko also was contractually committed to deliver approximately 9 MMBbls of crude oil to ports in Algeria and Ghana through 2014. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves.

Properties and Leases

The following shows the developed lease, undeveloped lease, and fee mineral acres in which Anadarko held interests at December 31, 2013:

	Developed Lease		Undeveloped Lease		Fee Mineral		Total	
thousands of acres	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States								
Onshore	4,804	3,151	5,269	2,498	10,318	8,452	20,391	14,101
Offshore	288	143	2,292	1,533	—	—	2,580	1,676
Total United States	5,092	3,294	7,561	4,031	10,318	8,452	22,971	15,777
International	546	130	66,104	43,856	—	—	66,650	43,986
Total	5,638	3,424	73,665	47,887	10,318	8,452	89,621	59,763

At December 31, 2013, the Company had approximately 7 million net undeveloped lease acres scheduled to expire by December 31, 2014, if the Company does not establish production or take any other action to extend the terms. 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 the Company's net acreage position to expire before such actions occur.

Drilling Program

The Company's 2013 drilling program focused on proven and emerging oil and natural-gas basins in the United States (onshore and deepwater Gulf of Mexico) and various international locations. Exploration activity in 2013 consisted of 175 gross completed wells, which included 162 U.S. onshore wells, 5 Gulf of Mexico wells, and 8 international wells. Development activity in 2013 consisted of 1,366 gross completed wells, which included 1,347 U.S. onshore wells, 1 Gulf of Mexico well, and 18 international wells.

Drilling Statistics

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

	Net Exploratory			Net Development			
	Productive	**Dry Holes**	**Total**	**Productive**	**Dry Holes**	**Total**	**Total**
2013							
United States	**62.9**	**1.4**	**64.3**	**879.3**	**3.3**	**882.6**	**946.9**
International	**0.2**	**3.5**	**3.7**	**5.4**	**—**	**5.4**	**9.1**
Total	**63.1**	**4.9**	**68.0**	**884.7**	**3.3**	**888.0**	**956.0**
2012							
United States	79.5	1.0	80.5	923.7	11.3	935.0	1,015.5
International	0.5	3.0	3.5	2.1	—	2.1	5.6
Total	80.0	4.0	84.0	925.8	11.3	937.1	1,021.1
2011							
United States	79.0	2.2	81.2	1,169.6	6.3	1,175.9	1,257.1
International	0.5	1.2	1.7	6.8	0.2	7.0	8.7
Total	79.5	3.4	82.9	1,176.4	6.5	1,182.9	1,265.8

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, 2013:

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion [(1)]	
	Exploration	**Development**	**Exploration**	**Development**
United States				
Gross	12	221	86	746
Net	5.7	165.0	39.1	426.9
International				
Gross	2	—	47	6
Net	0.9	—	17.9	1.7
Total				
Gross	14	221	133	752
Net	6.6	165.0	57.0	428.6

(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.

Productive Wells

At December 31, 2013, the Company's ownership interest in productive wells was as follows:

	Oil Wells (1)	Gas Wells (1)
United States		
Gross	3,796	29,415
Net	2,608.2	19,082.0
International		
Gross	355	8
Net	90.6	2.0
Total		
Gross	4,151	29,423
Net	2,698.8	19,084.0

(1) Includes wells containing multiple completions as follows:

Gross	229	2,865
Net	196.7	2,406.0

MIDSTREAM PROPERTIES AND ACTIVITIES

Anadarko invests in midstream (gathering, processing, treating, and transportation) 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, and keep-whole agreements. Anadarko's midstream activities include Western Gas Partners, LP (WES), which is a publicly traded limited partnership formed by Anadarko to own, operate, acquire, and develop midstream assets. WES's general partner is owned by Western Gas Equity Partners, LP (WGP), a publicly traded consolidated subsidiary formed to own substantially all of Anadarko's partnership interests in WES. At December 31, 2013, Anadarko's ownership interest in WGP consisted of a 91.0% limited partner interest and the entire non-economic general partner interest. At December 31, 2013, WGP's ownership interest in WES consisted of a 41.2% limited partner interest, the entire 2.0% general partner interest, and all WES incentive distribution rights. At December 31, 2013, Anadarko also owned a 0.4% limited partner interest in WES through another subsidiary.

At the end of 2013, Anadarko had 34 gathering systems and 31 processing and treating plants located throughout major onshore producing basins in Wyoming, Colorado, Utah, New Mexico, Kansas, Oklahoma, Pennsylvania, and Texas. In 2013, the Company's midstream activity was concentrated in liquids-rich growth areas such as Wattenberg, Greater Natural Buttes, the Delaware basin, the Eagleford shale, and East Texas/North Louisiana plays, as well as in the Marcellus shale dry-gas play. In 2014, the Company plans to continue midstream investments in these core areas.

Wattenberg The Company is constructing the 300-MMcf/d Lancaster cryogenic processing plant, with expected completion in early 2014. The plant will support the increasing production from horizontal drilling in the Niobrara development, helping to relieve processing constraints in the basin. The Company installed 180 MMcf/d of interim refrigeration processing capacity during 2013 to allow the Company's production to continue to grow in advance of the Lancaster Train I completion. In 2013, the Company sanctioned a second 300-MMcf/d cryogenic processing plant that will sit adjacent to Lancaster Train I. Engineering is underway and long-lead items have been ordered for Lancaster Train II, which is expected to be completed in the second quarter of 2015. Three separate compressor stations in other areas are scheduled to be in service in the first half of 2014, which will add an additional 184 MMcf/d of compression capacity.

Anadarko and joint-venture partners are currently constructing a 435-mile NGLs pipeline (Front Range Pipeline) with initial capacity of 150 MBbls/d and the ability to expand to 230 MBbls/d. The pipeline will transport NGLs from Weld County, Colorado to Skellytown, Texas, where it will connect with other pipelines, including the Texas Express Pipeline (TEP). The Front Range Pipeline is expected to be in service in the first quarter of 2014. During the third quarter of 2013, Anadarko and its partners placed the TEP in service. The TEP originates in Skellytown, Texas and extends approximately 580 miles to NGLs fractionation and storage facilities in Mont Belvieu, Texas. The capacity of the TEP is 280 MBbls/d and can be expanded to approximately 400 MBbls/d. The Front Range Pipeline and the TEP are expected to enhance the value of the Company's production by providing additional NGLs takeaway capacity and access to the Gulf Coast NGLs market. The Company acquired a 25% interest in an entity formed to design, construct, and own two fractionators located in Mont Belvieu, Texas. The two fractionation trains were placed in service late 2013.

Greater Natural Buttes A new inter-connect between a third-party pipeline and the Chipeta processing complex was completed during 2013, adding an additional 100 MMcf/d of natural-gas supply to the plant. Repairs and warranty work were performed on the two cryogenic trains at Chipeta during the year and the combined 550-MMcf/d cryogenic trains are now processing above capacity at a combined 600 MMcf/d. Construction also commenced to install an additional 100 MMcf/d of compression capacity at the Natural Buttes compressor station, which is expected to be completed in the first half of 2014.

Wyoming During the third quarter of 2013, the Company completed the purchase of a 242-mile pipeline between the Company's Granger and Patrick Draw plants in Wyoming. Also, an expansion project to build a 26-mile, 16-inch pipeline from the Horsetrap production area to the Patrick Draw plant was completed, adding 35 MMcf/d of natural-gas compression capacity.

Delaware Basin In the Delaware basin of West Texas, the Company expanded its midstream infrastructure for Bone Spring, Wolfcamp, and Avalon production. Projects were completed to increase oil and water capacity from 42 MBbls/d to a total of 47 MBbls/d through expansions at three central production facilities. In January 2013, the second phase of the Bone Spring processing plant, which is owned and operated by a third party, was commissioned and brought online with the start-up of a 100-MMcf/d cryogenic plant. Additionally, two new 20-MMcf/d central gathering facilities (CGF) were brought online in the Avalon area, bringing total CGF capacity in the area to 80 MMcf/d.

Eagleford In the Eagleford shale, the Anadarko-operated gathering systems were expanded to approximately 600 MMcf/d for natural gas and 75 MBbls/d for oil. Major projects completed in 2013 include the Maverick central delivery point/oil handling facility expansion, which includes 75 MBbls/d of oil stabilization capacity, the Cat Ranch Mega CGF (compressor station), the Stumberg Mega CGF (compressor station), and the expansion of the Cochina gathering system. The Brasada natural-gas processing plant was placed into service in the second quarter of 2013, adding 200 MMcf/d of natural-gas processing capacity and 15 MBbls/d of condensate stabilization capacity. The Company has agreements with a third party which provide for the transportation and sale of up to 35 MBbls/d of raw mix delivered from Cotulla, Texas. The Company has the right to expand this reserved capacity up to 70 MBbls/d.

East Texas/North Louisiana In East Texas, the Company continued to expand its midstream infrastructure for Cotton Valley Taylor and Haynesville production. The high-pressure Haynesville gathering system and related water and condensate infrastructure was expanded in the Carthage area to handle the continued growth associated with the liquids-rich Haynesville natural-gas production. Additionally, Anadarko has secured access to 490 MMcf/d of firm processing capacity for the Company's current and future development in East Texas.

Marcellus In the Marcellus shale in Pennsylvania, Anadarko's natural-gas gathering capacity increased from 1,500 MMcf/d in 2012 to over 1,650 MMcf/d in 2013. In 2013, the Company connected 71 Anadarko-operated wells, constructed 41 miles of new pipeline, and introduced third-party natural gas to the gathering system. The Bull Run Compressor Facility (2,700 horsepower) was commissioned in January 2013, with an additional 2,700-horsepower expansion completed in December 2013. The additional compression start-ups will enhance the long-term deliverability in the Bull Run development area. During 2013, the Company acquired a third party's 33.75% interest in the Larry's Creek, Seely, and Warrensville gas-gathering systems.

The following provides information regarding the Company's midstream assets by geographic regions:

Area	Asset Type	Miles of Gathering Pipelines	Total Horsepower	2013 Average Throughput (MMcf/d)
Rocky Mountains	Gathering, processing, and treating	11,300	1,166,400	3,800
Mid-Continent and other	Gathering	3,800	221,500	1,000
Texas	Gathering and treating	2,900	337,800	1,000
Total		18,000	1,725,700	5,800

MARKETING ACTIVITIES

The Company's marketing segment actively manages Anadarko's natural-gas, crude-oil, condensate, and NGLs sales, 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 natural gas, crude oil, condensate, and NGLs are generally made at market prices for those products at the time of sale. The Company also purchases natural gas, crude oil, condensate, and NGLs from third parties, primarily near Anadarko's production areas, to aggregate volumes so that the Company is positioned to utilize transportation and storage capacity fully, attract creditworthy customers, facilitate efforts to maximize prices received, and minimize balancing issues with customers and pipelines during operational disruptions.

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 natural gas, crude oil, condensate, and NGLs. The Company does not engage in market-making practices and limits its marketing activities to natural-gas, crude-oil, NGLs, and LNG commodity contracts. The Company's marketing-risk position is typically a net short position (reflecting agreements to sell natural gas, crude oil, 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 natural-gas and crude-oil reserves). See *Commodity Price Risk* under Item 7A of this Form 10-K.

Natural Gas Anadarko markets its natural-gas production to maximize value and to reduce the inherent risks of physical commodity markets. Anadarko's marketing segment offers supply-assurance and limited risk-management services at competitive prices, as well as other services that are tailored to its customers' needs. The Company may also receive a service fee related to the level of reliability and service required by the customer. 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. 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.

Crude Oil, Condensate, and NGLs Anadarko's crude-oil, condensate, and NGLs revenues are derived from production in the United States, Algeria, China, and Ghana. Most of the Company's U.S. crude-oil and NGLs production is sold under contracts with prices based on market indices, adjusted for location, quality, and transportation. Oil from Algeria is sold by tanker as Saharan Blend to customers primarily in the Mediterranean area. Saharan Blend is high-quality crude that provides refiners large quantities of premium products such as gasoline, diesel, and jet fuel. Oil from China is sold by tanker as Cao Fei Dian (CFD) Blend to customers primarily in the Far East markets. CFD Blend is a heavy sour crude oil which is sold into both the prime fuels refining market and the market for the heavy fuel oil blend stock. Oil from Ghana is sold by tanker as Jubilee Crude Oil to customers around the world. Jubilee Crude Oil is high-quality crude that provides refiners large quantities of premium products such as gasoline, diesel, and jet fuel. The Company also purchases and sells third-party-produced crude oil, condensate, and NGLs, and utilizes contracted NGLs storage facilities to capture market opportunities and reduce fractionation and downstream infrastructure disruptions.

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 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 21—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 5,700 employees at December 31, 2013.

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, and local environmental and occupational health and safety laws and regulations. These laws and regulations pertain to the discharge of materials into the environment; the generating, handling, and disposal of materials (including solid and hazardous wastes); the workplace health and safety of employees; or otherwise relating to the prevention, mitigation, or remediation of pollution, or the protection of natural resources, wildlife, or the environment. 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 and imposes various pre-construction, monitoring, and reporting requirements
- the U.S. Federal Water Pollution Control Act, also known as the federal Clean Water Act (CWA), which regulates discharges of pollutants from facilities to state and federal waters
- the U.S. Oil Pollution Act of 1990 (OPA), 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 strict liability for removal costs and damages arising from an oil spill in waters of the United States
- U.S. Department of the Interior (DOI) regulations, which relate to offshore oil and natural-gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, a remedial statute that imposes strict 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 controlling 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 disseminate information on chemical inventories to employees as well as local emergency planning committees and response departments
- 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 National Environmental Policy Act, which requires federal agencies, including the DOI, to evaluate major agency actions having the potential to impact the environment and which may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment
- 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 Marine Mammal Protection Act, which ensures the protection of marine mammals through the prohibition, with certain exceptions, of the taking of marine mammals in U.S. waters and by U.S. citizens on the high seas and which may require the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas
- the Migratory Bird Treaty Act, which implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds and, pursuant to which the taking, killing or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas

These and other laws and their implementing 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 development of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area. Compliance with these laws and regulations also, in most cases, requires new or amended permits that may contain new or more stringent technological standards or limits on emissions, discharges, disposals, or other releases in association with new or modified operations. Application for permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time-consuming. In addition, there can be delays associated with public notice and comment periods required prior to the issuance or amendment of a permit as well as the agency's processing of an application. Many of the delays associated with the permitting process are beyond the control of the Company.

Many states and foreign countries where the Company operates also have, or are developing, similar environmental laws, regulations, or analogous controls governing many of these same types of activities. While the legal requirements may be similar in form, 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 development of a project or substantially increase the cost of doing business.

Anadarko is also subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations.

Federal and state occupational safety and health laws require the Company to organize information about materials, some of which may be hazardous or toxic, that are used, released, stored, or produced in Anadarko's operations. Certain portions of this information must be provided to employees, state and local governmental authorities and responders, and local citizens. The Company is also subject to the safety hazard communication requirements and reporting obligations set forth in federal workplace standards.

There have been several regulatory and governmental initiatives related to the hydraulic-fracturing process, which could have an adverse impact on our completion or production activities. The U.S. Environmental Protection Agency (EPA) has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic-fracturing practices involving diesel notwithstanding the existence of current oil and gas regulations adopted at the state level. Moreover, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report expected to be available for public comment and peer review by 2014. The EPA has also announced plans to propose effluent limitations for the treatment and discharge of wastewater resulting from hydraulic-fracturing activities for shale gas. In May 2013, the federal Bureau of Land Management (BLM) published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands, replacing a prior proposed rulemaking issued in May 2012, that would require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. Certain other governmental reviews have been recently conducted or are underway that focus on environmental aspects of hydraulic-fracturing practices, including an evaluation by the U.S. Department of Energy, and coordination of an administration-wide review of these practices by the White House Council on Environmental Quality. Congress has from time to time considered bills that would regulate hydraulic fracturing and/or require public disclosure of chemicals used in the hydraulic-fracturing process. A number of states, including states in which the Company operates, have adopted or are considering legal requirements that could impose more stringent permitting, public disclosure, and well-construction requirements on hydraulic-fracturing activities. In addition, local government may seek to adopt ordinances within their jurisdictions regulating the time, place, and manner of drilling activities in general or hydraulic fracturing activities in particular; for example, local ballot initiatives in the Colorado cities of Boulder, Broomfield, Fort Collins, and Lafayette to restrict oil and gas development, including the use of hydraulic fracturing, either temporarily or permanently, within their respective city's limits were approved by voters in November 2013.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as new standards, such as air emission standards and water quality standards, continue to evolve. For example, in August 2012, the EPA published final rules under the federal Clean Air Act that subject oil and natural-gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from fractured gas wells for which well-completion operations are conducted. In 2013, the EPA reconsidered significant storage vessel requirements and will complete further reconsideration and rulemaking in 2014. In addition, environmental laws and regulations, including those that may arise to address concerns about global climate change and the threat of adverse impacts to groundwater arising from hydraulic-fracturing activities, are expected to continue to have an increasing impact on the Company's operations in the United States and in other countries in which Anadarko operates. Notable areas of potential impacts include air emission monitoring, compliance, mitigation, and remediation obligations in the United States.

The Company has reviewed its potential responsibilities under both OPA and CWA as they relate to the Deepwater Horizon events. OPA imposes joint and several liability on the responsible parties for all cleanup and response costs, natural resource damages, and other damages such as lost revenues, damages to real or personal property, damages to subsistence users of natural resources, and lost profits and earning capacity. While OPA requires that a responsible party pay for all cleanup and response costs, it currently limits liability for damages to $75 million, exclusive of response and remediation expenses (for which there is no cap), except in cases of gross negligence, willful misconduct, or the violation of an applicable federal safety, construction, or operating regulation. The federal government may take legislative or other action to increase or eliminate, perhaps even retroactively, the liability cap. As for damages to natural resources, the government may recover damages for injury to, loss of, destruction of, or loss of use of natural resources which may include the costs to repair, replace, or restore those or like resources. The CWA governs discharges into waters of the United States and provides for penalties in the event of unauthorized discharges into those waters. Under the CWA, these include, among other penalties, civil penalties that may be assessed in an amount up to $1,100 per barrel of oil discharged. In cases of gross negligence or willful misconduct, such civil penalties that may be sought by the United States are increased to not more than $4,300 per barrel of oil discharged.

As of the date of filing this Form 10-K with the SEC, no penalties or fines have been assessed by the federal government against the Company under OPA, CWA, and other similar local, state and federal environmental legislation related to the Deepwater Horizon events. However, in December 2010, the U.S. Department of Justice, on behalf of the United States, filed a civil lawsuit in the U.S. District Court in New Orleans, Louisiana, against several parties, including the Company, seeking (i) an assessment of civil penalties under the CWA in an amount to be determined by the court, and (ii) a declaratory judgment that such parties are jointly and severally liable without limitation under OPA for all removal costs and damages resulting from the Deepwater Horizon events. In October 2011, the Company and BP Exploration & Production Inc. (BP) entered into a settlement agreement, mutual releases, and agreement to indemnify relating to the Deepwater Horizon events (Settlement Agreement), pursuant to which BP has agreed to fully indemnify Anadarko against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events and related damage claims arising under OPA. Under the Settlement Agreement, BP does not indemnify the Company against penalties or fines that may be assessed against the Company as a result of the Deepwater Horizon events, including for example, penalties or fines under the CWA. For additional information, see *Note 17—Contingencies—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

The Company has made and will continue to make operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. These are necessary business costs in the Company's operations and in the oil and natural-gas industry. 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 resulting from the Company's operations, could result in substantial costs and liabilities, including administrative, civil, and criminal penalties, to Anadarko. The Company believes that it is in material compliance with existing environmental and occupational health and safety regulations. Further, the Company believes that the cost of maintaining compliance with these existing laws and regulations will not have a material adverse effect on its business, financial position, results of operations, or cash flows, but new or more stringently applied existing laws and regulations could increase the cost of doing business, and such increases could be material.

Oil Spill-Response Plan

Domestically, the Company is subject to compliance with the 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 Company has filed the information that describes the Company's ability to deploy surface and subsea containment resources to adequately and promptly respond to a blowout or other loss of well control. The BSEE regulations may be amended, resulting in 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 both Regional (Central and Western Gulf of Mexico) and Sub-Regional (Eastern Gulf of Mexico) Oil Spill-Response Plans (Plans) for the Company's Gulf of Mexico operations. The Plans detail procedures for a rapid and effective response to spill events that may occur as a result of Anadarko's operations. The Plans are reviewed at least annually and updated as necessary. Drills are conducted at least annually to test the effectiveness of the Plans and include the participation of spill-response contractors, representatives of Clean Gulf Associates (CGA, a not-for-profit association of production and pipeline companies operating in the Gulf of Mexico contractually engaged by the Company for such matters), and representatives of relevant governmental agencies. 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 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.

CGA equipment includes the following: High Volume Open Sea Skimmer System (HOSS) barge, 95-foot skimming vessels, 46-foot skimming vessels, 56-foot skimming vessels, Marco skimmers, and Egmopol skimmers. Additional available equipment includes the following: fast response units, rope mop, barges, skimming arms, skim packages, and tanks. In addition, auto boom, beach boom, and fire boom are currently available through CGA. CGA also has a stockpile of Corexit 9500 dispersant spray system through Airborne Support Inc. (ASI), a wildlife rehabilitation trailer, and bird scare guns. CGA currently has one X-band radar installed on the HOSS barge.

CGA has executed a support contract with T&T Marine to coordinate bareboat charters and provides for expanded response support. T&T Marine is responsible for inspecting, maintaining, storing, and calling out CGA equipment. T&T Marine has positioned CGA's equipment and materials in a ready state at various staging areas around the Gulf of Mexico.

T&T Marine also handles the maintenance and mobilization of CGA non-marine equipment. T&T Marine has service contracts in place with domestic environmental contractors as well as with other companies that provide support services during the execution of spill-response activities. In the event of a spill, T&T Marine will activate these contracts as necessary to provide additional resources or support services requested by CGA. In addition, CGA maintains a service contract with ASI, which provides aircraft and dispersant capabilities for CGA member companies.

Anadarko is also a member of the Marine Preservation Association, which provides full access to the Marine Spill Response Corporation (MSRC) cooperative including the Deep Blue enhanced Gulf of Mexico Response capability. 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 specifically to recover spilled oil. Each OSRV is approximately 210 feet long, has temporary storage for recovered oil, and has the ability to separate oil and water aboard the vessels using two oil-water separation systems. To enable the OSRV to sustain cleanup operations, recovered oil can be transferred into other vessels or barges.

MSRC has equipment housed for the Atlantic Region, the Gulf of Mexico Region, the California Region, and the Pacific Northwest Region. The Gulf of Mexico Region has a total of approximately 60 skimmers with an Effective Daily Recovery Capacity (EDRC) of approximately 562,000 barrels. The California Region has approximately 278,000 barrels EDRC and the Pacific Northwest Region has approximately 335,000 barrels EDRC. Additional available equipment includes the following: OSRVs, fast response vessels, barges, storage bladders, work boats, ocean boom, and dispersant.

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 all oil and gas operators in the 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 and this employee currently serves as its Chair. MWCC members have access to an interim containment system that includes a 15-kpsi capping stack and dispersant capability. The interim containment system is engineered to operate in deepwater depths of up to 10,000 feet, and has the capacity to contain 60 MBbls/d of liquids and flare 120 MMcf/d of natural gas. The DOI has reviewed the functional specifications of the MWCC interim containment system, and DOI input was included in the final specifications.

MWCC members also expect to have access to an expanded 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. The expanded system is planned to include a 15-kpsi subsea containment assembly with three rams stack, dedicated capture vessels, and a dispersant injection system. The expanded containment system may be further expanded with additional capture vessels, modified tankers, drill ships, and extended well-test vessels, all of which may process, store, and offload oil to shuttle tankers, which may then take the oil to shore for further processing. This expanded containment system is currently scheduled for delivery by mid-2014.

Anadarko retains geospatial and satellite imagery services through the MDA Corporation (MDA) to provide coverage over the Company's Gulf of Mexico operations. MDA owns and maintains two radar satellites, RADARSAT-1 and RADARSAT-2, which provide all-weather surveillance and imagery available to assist in identifying areas of concern on the surface waters of the Gulf of Mexico. The Company has agreements with Waste Management, Inc. and Clean Harbors to assist in the proper disposal of contaminated and hazardous waste soil and debris. In addition, Anadarko has agreements with HDR Engineering, Inc. (HDR) for assistance with Subsea Dispersant applications. Staff members of HDR are recognized as worldwide experts in the proper use of dispersants in a subsea application, developing scientific methods for determining the proper injection, and monitoring of the dispersant while maintaining the environmental and ecosystem integrity and health. The Company also has agreements with TDI-Brooks International for its scientific research vessels to properly monitor the effectiveness of the dispersant application and the health of the ecosystem. The Company also has agreements with Scientific and Environmental Associates, Inc. (SEA) for assistance with surface-dispersant applications. SEA is a scientific support consulting firm providing subject matter experts, and is renowned for its expertise in surface-dispersion applications and efficacy monitoring.

Anadarko has emergency and oil spill-response plans in place for each of its exploration and operational activities around the globe. Each plan satisfies the requirements of relevant local or national authority, describes the actions the Company will take in the event of an incident, is subject to drills 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. OSRL maintains specialized equipment in a ready state for deployment in the event such equipment is needed by one of its members. OSRL is mainly available for response internationally, but its equipment is registered with the U.S. Coast Guard for domestic use if needed.

OSRL has one 727 aircraft, located in the United Kingdom and one Hercules aircraft, located in Singapore, available for dispersant application or equipment transport. The aircraft have a three-hour callback time. The Hercules can transport two to three pre-packaged equipment loads, or one Aerial Dispersant Delivery System (ADDS) Pack. OSRL has three ADDS Packs: one in the United Kingdom, one in Bahrain, and one in Singapore. If additional aircraft are needed, OSRL retains an aircraft broker so that an aircraft can be chartered. For international operations, the majority of equipment will be air freighted.

OSRL has a number of active recovery boom systems, and a range of booms that can be used for offshore, nearshore, or shoreline responses. Offshore boom is stored in the United Kingdom, Bahrain, and Singapore. Fireboom systems have been delivered and a team is trained to operate the system. A variety of nearshore boom exists for spill containment.

OSRL also provides a range of communications equipment, safety equipment, transfer pumps, dispersant application systems, temporary storage equipment, power packs and generators, small inflatable vessels, rigid inflatable boats, work boats, and Fast Response Vessels. Oleophilic, weir, and mechanical skimmers provide the ability to recover a range of oil types. OSRL also has a wide range of oiled wildlife equipment in conjunction with the Sea Alarm Foundation.

During 2013, Clean Caribbean and Americas, a cooperative located in Fort Lauderdale, Florida, was integrated into OSRL and assets now available to OSRL members include an ADDS Pack, dispersant stockpile, and a depot of mechanical containment and recovery systems.

In addition, during 2013, a small group of exploration and production companies reached an agreement as a subset of OSRL to develop the Global Dispersant Stockpile of 5,000 cubic meters of dispersant designed to support response efforts for up to 30 days or until the dispersant production facilities could take up production.

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, a thorough title examination of the drill site tract is 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, 2014	Position
R. A. Walker	56	Chairman, President and Chief Executive Officer
Robert P. Daniels	55	Executive Vice President, International and Deepwater Exploration
Robert G. Gwin	50	Executive Vice President, Finance and Chief Financial Officer
James J. Kleckner	56	Executive Vice President, International and Deepwater Operations
Charles A. Meloy	53	Executive Vice President, U.S. Onshore Exploration and Production
Robert K. Reeves	56	Executive Vice President, General Counsel and Chief Administrative Officer
M. Cathy Douglas	57	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 Western Gas Holdings, LLC (WGH), the general partner of WES, and served as its Chairman of the Board from August 2007 to September 2009. Mr. Walker served as a director of Western Gas Equity Holdings, LLC (WGEH), the general partner of WGP, from September 2012 until March 2013. Mr. Walker served as a director of Temple-Inland Inc. from November 2008 to February 2012 and has served as a director of CenterPoint Energy, Inc. since April 2010 and as a director of BOK Financial Corporation since April 2013.

Mr. Daniels was named Executive Vice President, International and Deepwater Exploration in May 2013 and previously served as Senior Vice President, International and Deepwater Exploration since July 2012. Prior to these positions, he served as Senior Vice President, Worldwide Exploration since December 2006 and served as Senior Vice President, Exploration and Production since May 2004. Prior to that position, he served as Vice President, Canada since July 2001. Mr. Daniels also served in various managerial roles in the Exploration Department for Anadarko Algeria Company, LLC. He has worked for the Company since 1985.

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. Kleckner was named Executive Vice President, International and Deepwater Operations in May 2013. Prior to this position, he served as Vice President, Operations for the Rockies region since May 2007. Mr. Kleckner 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 management roles in the North Sea, South America, China, the Gulf of Mexico and U.S. onshore. Prior to joining Kerr-McGee Corporation, Mr. Kleckner was in the oil and natural-gas industry with Oryx Energy Company and its predecessor, Sun Oil Company.

Mr. Meloy was named Executive Vice President, U.S. Onshore Exploration and Production in May 2013 and previously served as Senior Vice President, U.S. Onshore Exploration and Production since July 2012. Prior to this position, he served as Senior Vice President, Worldwide Operations since December 2006 and served as Senior Vice President, Gulf of Mexico and International Operations since the acquisition of Kerr-McGee Corporation in August 2006. Prior to joining Anadarko, he served Kerr-McGee Corporation as Vice President of Exploration and Production from 2005 to 2006, Vice President of Gulf of Mexico Exploration, Production and Development from 2004 to 2005, Vice President and Managing Director of Kerr-McGee North Sea (U.K.) Limited from 2002 to 2004 and Vice President of Gulf of Mexico Deepwater from 2000 to 2002. Prior to joining Kerr-McGee Corporation, Mr. Meloy was in the oil and natural-gas industry with Oryx Energy Company and its predecessor, Sun Oil Company. Mr. Meloy has served as a director of WGH since February 2009 and as a director of WGEH since September 2012.

Mr. Reeves was named Executive Vice President, General Counsel and Chief Administrative Officer in May 2013 and previously served 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 has served as a director of Key Energy Services, Inc., a publicly traded oilfield services company, since October 2007, as a director of WGH since August 2007 and as a director of WGEH since September 2012.

Ms. Douglas was named Senior Vice President, Chief Accounting Officer and Controller in May 2013. Prior to this position, she served as Vice President and Chief Accounting Officer since November 2008 and served as Corporate Controller from September 2007 to March 2009 and from March 2013 to May 2013. She served as Assistant Controller from July 2006 to September 2007. She also served as Director, Accounting, Policy and Coordination from October 2006 to September 2007 and Financial Reporting and Policy Manager from January 2003 to October 2006. Ms. Douglas joined Anadarko in 1979.

Officers of Anadarko are elected each year at the first meeting of the Board of Directors following the annual meeting of stockholders, the next of which is expected to occur on May 13, 2014, 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 report, 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 and Section 21E of the Securities Exchange Act of 1934 concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include 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 levels*
- *reserves levels*
- *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 commercializing and transporting of natural gas, crude oil, natural gas liquids (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 risks*
- *future processing volumes and pipeline throughput*
- *general economic conditions, either internationally or nationally or in the jurisdictions in which the Company or its subsidiaries are doing business*
- *the Company's inability to timely obtain or maintain permits, including those necessary for drilling and/or development projects*
- *legislative or regulatory changes, including retroactive royalty or production tax regimes; hydraulic-fracturing regulation; deepwater drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation; environmental risks; and liability under federal, state, foreign, and local environmental laws and regulations*

- *ability of BP Exploration & Production Inc. (BP) to meet its indemnification obligations to the Company for Deepwater Horizon events, including, among other things, damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and associated damage-assessment costs, and any claims arising under the Operating Agreement (OA) for the Macondo well, as well as the ability of BP Corporation North America Inc. (BPCNA) and BP p.l.c. to satisfy their guarantees of such indemnification obligations*
- *impact of remaining claims related to the Deepwater Horizon events, including, but not limited to, fines, penalties, and punitive damages against the Company, for which it is not indemnified by BP*
- *current and potential legal proceedings, or environmental or other obligations related to or arising from Tronox Incorporated (Tronox)*
- *civil or political unrest or acts of terrorism in a region or country*
- *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 its debt, and the impact of changes in the Company's credit ratings*
- *disruptions in international crude oil cargo shipping activities*
- *physical, digital, internal, and external security breaches*
- *supply and demand, technological, political, and commercial conditions associated with long-term development and production projects in domestic and international locations*
- *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*

We are, and in the future may become, involved in legal proceedings related to Tronox and, as a result, may incur substantial liabilities in connection with those proceedings, which could have a material adverse effect on our business, prospects, results of operations, cash flows, financial condition, and liquidity.

In January 2009, Tronox, a former subsidiary of Kerr-McGee Corporation, which is a current subsidiary of Anadarko, and certain of Tronox's subsidiaries filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York (Bankruptcy Court). Subsequently, in May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) asserting a number of claims, including claims for actual and constructive fraudulent conveyance (Adversary Proceeding). Tronox alleged, among other things, that it was insolvent or undercapitalized at the date of its initial public offering and sought, among other things, to recover damages from Kerr-McGee and Anadarko, as well as interest, appreciation, and attorneys' fees and costs. See *Note 17—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for the nature and status of this litigation and the Company's liability accrual.

As a result of the Bankruptcy Court's finding of liability in its *Memorandum of Opinion, After Trial* (Opinion) issued in December 2013, the Company believes that a loss in the Adversary Proceeding is probable and has recorded a liability of $850 million at December 31, 2013. The Company's liability is based on the application of relevant accounting guidance and law to the information known to the Company at this time. The Bankruptcy Court has not entered a judgment against Kerr-McGee because the Bankruptcy Court has not resolved questions it raised concerning the appropriate application of bankruptcy law to Kerr-McGee's right to an offset claim that would reduce the amount of damages to be awarded to the plaintiffs. As the post-trial proceedings continue, the Bankruptcy Court issues a judgment and the parties consider appeal, it is possible that the Company may be required to increase the accrued liability related to the Adversary Proceeding.

While we currently expect to fully pursue all rights available through the appellate process, the Company cannot guarantee success on appeal. If the Company is ultimately required to pay a judgment, the Company may be required to access its $5.0 billion Facility, enter into new or amended financing arrangements, identify and divest assets and/or use cash flows from operations to secure sufficient funds. The Company's liabilities relating to Tronox could exceed current estimates, and we could incur additional liabilities that we are unable to estimate or predict at this time. These events could have a material adverse effect on our business, prospects, consolidated financial position, results of operations, cash flows, financial condition, and liquidity.

During the appeals process, the Company may be required to post a bond or provide sufficient security within 14 days of a judgment to stay execution of the judgment by the plaintiffs pending the outcome of the appellate process. Depending on the amount of a judgment, there is no guarantee that the Company will be able to post a bond in a timely manner or provide security at levels acceptable to the Bankruptcy Court.

The Company's ability to post a bond or provide sufficient security to stay a judgment depends on a variety of factors, including, but not limited to, the amount of the judgment, the willingness of the Bankruptcy Court to accept alternative forms of security, the willingness of bond providers to issue bonds in the required amount or at all, and the proposed terms of such bonds. The Company may be required to access existing or new financing arrangements and monetize or pledge assets in order to post a bond or provide any such required security. There is no assurance that the Company would be able to take such actions on acceptable terms or at all. In addition, any such financing arrangements could subject the Company to covenants imposing additional or more burdensome restrictions on the Company's business, relative to the covenants currently contained in the $5.0 billion Facility and other existing debt agreements. Moreover, the Company could incur significant fees or costs to obtain and maintain a bond or additional financing arrangements.

A downgrade or other negative rating action with respect to our credit rating could negatively impact our cost of and ability to access capital.

In December 2013, following the Bankruptcy Court's issuance of the Opinion relating to Tronox, Standard and Poor's (S&P) affirmed its "BBB-" rating of the Company's debt but revised its outlook from "positive" to "negative" and Moody's Investors Service (Moody's) affirmed its "Baa3" rating but revised its outlook from "positive" to "developing." At that time, Fitch Ratings (Fitch) announced no change to its "BBB-" rating with a stable outlook. As of the date of this Form 10-K, no changes in the Company's credit ratings have occurred and we are not aware of any current plans of S&P, Moody's, or Fitch to lower their respective ratings on our debt. However, we cannot provide assurance that our credit ratings will not be downgraded or otherwise negatively affected, especially at the time the Bankruptcy Court issues a judgment, depending on the amount of the judgment. A downgrade of our credit ratings could negatively impact our cost of capital and our ability to access capital markets, increase our costs under our $5.0 billion Facility, and limit our ability to effectively execute aspects of our strategy.

In addition, a downgrade or other negative rating action could affect the Company's requirements to post collateral as financial assurance of its performance under certain contractual arrangements, such as pipeline transportation contracts, oil and gas sales contracts, and work commitments. Following the December 2013 outlook revisions by S&P and Moody's, $17 million of letters of credit were provided as assurance of the Company's performance under these types of arrangements. A downgrade or other negative rating action could also prompt requests by some of Anadarko's business partners for the Company to post additional collateral in the form of letters of credit or cash.

A downgrade could also trigger provisions in certain of the Company's derivative instruments that can require full or partial collateralization or immediate settlement of the Company's obligations. Most of the Company's derivative counterparties maintain secured positions with respect to the Company's derivative liabilities under the Company's $5.0 billion Facility, and if such facility terminates, the Company may be required to post collateral pursuant to existing credit support arrangements. A downgrade could also cause the Company's credit thresholds with such derivative counterparties to be reduced or eliminated, increasing the amount of collateral required. The aggregate fair value of all derivative instruments with credit-risk-related contingent features for which a net liability position existed at December 31, 2013, was $42 million (net of collateral). See *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

We may be subject to claims and liabilities relating to the Deepwater Horizon events that are not covered by BP's indemnification obligations under our Settlement Agreement with BP, or that result in losses to the Company, notwithstanding BP's indemnification against such losses, as a result of BP's inability to satisfy its indemnification obligations under the Settlement Agreement and BPCNA's and BP p.l.c.'s inability to satisfy their guarantees of BP's indemnification obligations.

In October 2011, the Company and BP entered into a settlement agreement, mutual releases, and agreement to indemnify relating to the Deepwater Horizon events (Settlement Agreement). Pursuant to the Settlement Agreement, the Company is fully indemnified by BP against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under OPA, NRD claims and assessment costs, and any claims arising under the OA. This indemnification is guaranteed by BPCNA and, in the event that the net worth of BPCNA declines below an agreed-on amount, BP p.l.c. has agreed to become the sole guarantor.

Any failure or inability on the part of BP to satisfy its indemnification obligations under the Settlement Agreement, or on the part of BPCNA or BP p.l.c. to satisfy their respective guarantee obligations, could subject us to significant monetary liability beyond the terms of the Settlement Agreement, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity. In November 2012, BP settled all criminal and securities claims brought by the United States against BP, with BP agreeing to pay $4.0 billion over five years to the U.S. Department of Justice with respect to the criminal claims and further agreeing to pay another $525 million over three years to the Securities and Exchange Commission (SEC) with respect to the securities claims. BP represents that it is prepared to vigorously defend itself against remaining civil claims. Furthermore, in certain instances we may be required to recognize a liability for amounts for which we are indemnified in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. Any such liability recognition without collection of the offsetting receivable could adversely impact our results of operations, our financial condition, and our ability to make borrowings.

Under the Settlement Agreement, BP does not indemnify the Company against fines and penalties, punitive damages, shareholder derivative or securities laws claims, or certain other claims. The adverse resolution of any current or future proceeding related to the Deepwater Horizon events for which we are not indemnified by BP could subject us to significant monetary liability, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Oil, natural-gas, and NGLs prices are volatile. 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, 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:

- domestic and worldwide supply of, and demand for, oil, natural gas, and NGLs
- volatile trading patterns in the commodity-futures markets
- cost of exploring for, developing, producing, transporting, and marketing oil, natural gas, and NGLs
- level of global crude-oil and natural-gas inventories
- weather conditions
- potential U.S. exports of liquefied natural gas or crude oil
- ability of the members of the Organization of Petroleum Exporting Countries (OPEC) and other producing nations to agree to and maintain production levels
- worldwide military and political environment, civil and political unrest in Africa and the Middle East, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities, or further acts of terrorism in the United States, or elsewhere

- effect of worldwide energy conservation and environmental protection efforts
- price and availability of alternative and competing fuels
- price and level of foreign imports of oil, natural gas, and NGLs
- domestic and foreign governmental regulations and taxes
- 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 declines in these commodity prices may have the following effects on our business:

- adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures, and results of operations
- reducing the amount of oil, natural gas, and NGLs that we can produce economically
- causing us to delay or postpone some of our capital projects
- reducing our revenues, operating income, or cash flows
- reducing the amounts of our estimated proved oil and natural-gas reserves
- reducing the carrying value of our oil and natural-gas properties
- reducing the standardized measure of discounted future net cash flows relating to oil and natural-gas reserves
- limiting our access to, or increasing the cost of, sources of capital, such as equity and long-term debt

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 federal, provincial, 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, hydraulic fracturing, and environmental protection regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various federal, provincial, regional, state, tribal, and local governmental authorities. Government disruptions, such as an extended federal government shutdown resulting from the failure to pass budget appropriations, adopt continuing funding resolutions or raise the debt ceiling, could delay or halt the granting and renewal of such permits, approvals, and certificates required to conduct our operations. As a result, activity in the affected regions, such as the Gulf of Mexico and on federal and Indian lands in the United States, could be adversely affected or delayed. In addition, the adoption of government payment transparency regulations could harm our competitiveness or relations with other governments or third parties. We may also incur substantial costs to maintain compliance with these existing laws and regulations. Our costs of compliance may increase if existing laws, including environmental and tax laws and regulations, are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For example, from time to time, legislation has been proposed that could adversely affect our business, financial condition, results of operations, or cash flows related to the following:

- *Climate Change.* A number of state and regional efforts have emerged that are aimed at tracking and/or reducing emissions of green-house gases (GHGs). In addition, the U.S. Environmental Protection Agency (EPA) has made findings that emissions of GHGs present a danger to public health and the environment and, based on these findings, has adopted regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act. We may be required to install “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. In addition, certain operations are subject to EPA rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore production sources in the United States on an annual basis.

- *Deficit Reduction or Tax Reform.* Congress may undertake significant deficit reduction or comprehensive tax reform in the coming year. Proposals include provisions that would, if enacted, (i) eliminate the immediate deduction for intangible drilling and development costs, (ii) eliminate the manufacturing deduction for oil and gas qualified production activities, and (iii) eliminate accelerated depreciation for tangible property.

Federal, state, and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an essential and common practice used to stimulate production of natural gas and/or oil from dense subsurface rock formations such as shales that generally exist between 4,000 and 14,000 feet below ground. 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, and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the oil or natural gas to flow to the wellbore. The process is typically regulated by state oil and natural-gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and in its semi-annual regulatory agenda published in July 2013, the agency continues to project the issuance of an Advance Notice of Proposed Rulemaking, but it does not state a deadline for such issuance. In May 2013, the BLM published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands, replacing a prior proposed rulemaking issued in May 2012, that would require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. In addition, Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In the event that a new, federal level of legal restrictions relating to the hydraulic-fracturing process is adopted in areas where we currently or in the future plan to operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Certain states in which we operate, including Colorado, Pennsylvania, Louisiana, Texas, Ohio, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, and additional well-construction requirements on hydraulic-fracturing operations. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular; for example, local ballot initiatives in the Colorado cities of Boulder, Broomfield, Fort Collins, and Lafayette to restrict oil and gas development, including the use of hydraulic fracturing, either temporarily or permanently, within their respective cities' limits were approved by voters in November 2013. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic-fracturing activities. Nonetheless, in the event state or local restrictions or prohibitions are adopted in areas where we currently conduct operations, or in the future plan to conduct operations, we may incur significant costs to comply with such requirements or we may experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Depending on the state or area in which they are adopted, such restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

There are also certain governmental reviews recently conducted or underway that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012, and a final draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic-fracturing activities and plans to propose these standards for shale gas by 2014. In addition, the U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods and, in August 2011, issued a report on immediate and longer-term actions that may be taken to reduce environmental and safety risks of shale-gas development. Also, as discussed above, the BLM is pursuing regulations governing hydraulic fracturing on federal and Indian oil and gas leases. These studies, depending on any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

The additional deepwater drilling laws and regulations, both domestically and internationally, delays in the processing and approval of drilling permits and exploration and oil spill-response plans, and other related developments arising after the deepwater drilling moratorium in the Gulf of Mexico may have a material adverse effect on our business, financial condition, or results of operations.

In response to the Deepwater Horizon incident in the Gulf of Mexico in April 2010, the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement, each agencies of the U.S. Department of the Interior, issued directives in May and July 2010 requiring lessees and operators of federal oil and gas leases in the Outer Continental Shelf (OCS) regions of the Gulf of Mexico and Pacific Ocean to cease drilling all new deepwater wells, including wellbore sidetracks and bypasses, but excluding workovers, completions, plugging and abandonment, or production, through November 30, 2010. In addition, the agencies issued a series of rules and Notices to Lessees and Operators imposing new and more stringent regulatory safety and performance requirements and permitting procedures for new wells to be drilled in federal waters of the OCS. If similar events were to occur in the future, the United States or other countries could elect to again 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.

Compliance with these new and more stringent rules and regulations, uncertainties or inconsistencies in current decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits and exploration, development, and oil spill-response plans, as a result of the new laws and regulations, and possible additional regulatory initiatives could adversely affect or delay new drilling and ongoing development efforts. Among other adverse impacts, these additional measures could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased costs and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or all of our facilities. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling operations or on the cost or availability of insurance to cover the risks associated with such operations.

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 the Company's oil spill-response capabilities, it may be difficult for us to quickly or effectively execute any contingency plans related to future events similar to the Deepwater Horizon incident.

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.

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

Our total debt was $13.6 billion at December 31, 2013. 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 realize the value of our assets and opportunities fully 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 agreement governing our senior secured revolving credit facility ($5.0 billion Facility) contains a number of covenants that impose operating and financial constraints on the Company, including restrictions on our ability to incur additional indebtedness, sell assets, and incur liens. Provisions of the $5.0 billion Facility also require us to maintain specified financial covenants as further described in *Liquidity and Capital Resources* under Item 7 of this Form 10-K. Our ability to meet such covenants may be affected by events beyond our control.

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 report 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 and natural-gas 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:

- historical production from an area compared with production from similar producing areas
- assumed effects of regulation by governmental agencies and court rulings
- assumptions concerning future oil and natural-gas 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 report 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 average 12-month sales prices using the average beginning-of-month price. 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.

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.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

A portion of our leasehold acreage is currently undeveloped. Unless production in sufficient quantities is established on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based on various factors: drilling results, oil and natural-gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

Poor general 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, the U.S. mortgage market, uncertainties with regard to European sovereign debt, and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices. If economic recovery in the United States or abroad is prolonged, demand for petroleum products could diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs; affect our vendors', suppliers' and customers' ability to continue operations; and ultimately adversely impact our results of operations, liquidity, and financial condition.

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

As a result of mergers and acquisitions, we had approximately $5.5 billion of goodwill on our Consolidated Balance Sheet at December 31, 2013. 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 lead to an impairment of goodwill, such as the Company's inability to replace the value of its depleting asset base, difficulty or potential delays in obtaining drilling permits, or other adverse events, such as lower sustained oil and natural-gas prices, which could reduce the fair value of the associated reporting unit. An impairment of goodwill could have a substantial negative effect on our profitability.

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 federal, provincial, 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, and midstream activities
- protection of endangered species
- amounts and types of emissions and discharges
- generation, management, and disposition of waste materials
- offshore oil and gas operations and decommissioning of abandoned facilities
- reclamation and abandonment of wells and facility sites
- remediation of contaminated sites

In addition, 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 development of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area. Future environmental laws and regulations, such as the restriction against emission of pollutants from previously unregulated activities or the designation of previously unprotected species as threatened or endangered in areas where we operate, may negatively impact our industry. The cost of satisfying these requirements may have an adverse effect on our financial condition, results of operations, or cash flows or could result in limitations on our exploration and production activities, which could have an adverse impact on our ability to develop and produce our reserves. For a description of certain environmental proceedings in which we are involved, see *Note 17—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

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, Mozambique, Ghana, China, Brazil, Kenya, Côte d'Ivoire, Liberia, Sierra Leone, New Zealand, Colombia, South Africa, and other countries. Our operations and financial results could be significantly impacted by conditions in some of these areas because we are vulnerable to certain unique risks associated with operating offshore, including those relating to the following:

- hurricanes and other adverse weather conditions
- oilfield service costs and availability
- compliance with environmental and other laws and regulations
- terrorist attacks, such as piracy
- remediation and other costs and regulatory changes resulting from oil spills or releases of hazardous materials
- failure of equipment or facilities

In addition, we conduct some of our exploration in deep waters (greater than 1,000 feet) where operations 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 its 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.

Further, production of reserves from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years of production and, as a result, our reserves replacement needs from new prospects may be greater there than for our operations elsewhere. Also, our revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods.

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

Our operations outside the United States are based primarily in Algeria, Brazil, China, Colombia, Côte d'Ivoire, Ghana, Kenya, Liberia, Mozambique, New Zealand, Sierra Leone, and South Africa. 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

For example, Ghana and Côte d'Ivoire are currently engaged in a dispute regarding the international maritime and land boundaries between the two countries. As a result, Côte d'Ivoire claims to be entitled to the maritime area which covers a portion of the Deepwater Tano Block where we are currently developing the TEN complex. In the event Côte d'Ivoire is successful in its maritime border claims, this development could be materially impacted. More recently, Venezuela has engaged Guyana in a dispute with regard to their maritime and land borders. Anadarko was forced to stop a seabed study undertaken within Guyana's Exclusive Economic Zone pursuant to contractual rights granted by Guyana when a Venezuelan naval vessel escorted the vessel to a Venezuelan port because it claims the area as being within its national maritime territory. The two countries have initiated a dialogue. At this time we are unable to ascertain the full impact of this maritime border dispute on future operations in Guyana.

Outbreaks of civil and political unrest and acts of terrorism have occurred in several countries in Africa and the Middle East, including countries where we conduct operations, such as Algeria and Tunisia. As exhibited by the events in Tunisia, Egypt, and Libya, outbreaks of civil and political unrest have resulted in established governing bodies being overthrown. 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 by laws and policies of the United States affecting foreign trade and taxation.

Realization of any of the factors listed above could materially and adversely affect our financial position, 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 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 and natural-gas prices

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse effect on the Company's ability to use derivative instruments to reduce the effect of commodity-price, interest-rate, and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), enacted in 2010, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when this will be accomplished.

The Dodd-Frank Act authorized the CFTC to establish rules and regulations setting position limits for certain futures contracts in designated physical commodities and for options and swaps that are their economic equivalents. The CFTC's initial position-limits rules were vacated by the U.S. District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. It is not possible at this time to predict when the CFTC will finalize these regulations; therefore, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest-rate swaps and credit-default swaps for mandatory clearing and exchange trading. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although the Company believes that it qualifies for the end-user exception from the mandatory clearing and trade execution requirements for swaps entered to manage its commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that the Company uses for hedging. In addition, the Dodd-Frank Act requires that regulators establish margin rules for uncleared swaps. Rules that require end-users to post initial or variation margin could impact liquidity and reduce our cash available for capital expenditures, therefore reducing our ability to enter into derivatives to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore, the impact of those provisions to us is uncertain at this time.

The Dodd-Frank Act and regulations may also result in counterparties to the Company's derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. In addition, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices. The Company's revenues could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Company encounters, reduce the Company's ability to monetize or restructure its existing derivative contracts, and increase the Company's exposure to less-creditworthy counterparties. If the Company reduces its use of derivatives as a result of the Dodd-Frank Act and regulations, the Company's results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect the Company's ability to plan for and fund capital expenditures.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent the Company transacts with counterparties in foreign jurisdictions, it may become subject to such regulations. At this time, the impact of such regulations is not clear.

Any of these consequences could have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

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 facility 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 facility. Moreover, to the extent that purchasers of the Company's 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 the Company if such purchasers were unable to access the credit or equity markets for an extended period of time.

We are not insured against all of the operating risks to which our business is exposed.

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and gas, including blowouts; cratering and fire; environmental hazards, such as 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. For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/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 consolidated financial position, results of operations, or cash flows.

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 by joint-venture partners
- timely issuance of permits and licenses by governmental agencies or legislative and other governmental approvals
- weather conditions
- availability of personnel
- civil and political environment of the country or region in which the project is located
- manufacturing and delivery schedules of critical equipment
- commercial arrangements for pipelines 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 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.

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. During these periods, the costs of rigs, equipment, supplies, and personnel are substantially greater 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.

Our drilling activities may not be productive.

Drilling for oil and natural gas involves numerous risks, including the risk that we will not encounter commercially productive oil or natural-gas reservoirs. The costs of drilling, completing, and operating wells are often uncertain, and 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
- shortages or delays in the delivery of equipment

Certain of our future drilling activities may not be successful and, if unsuccessful, this failure could have an 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 of the percentage of our capital budget devoted to high-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 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 and lead to unexpected future costs.

Our ability to sell our oil and gas production could be materially harmed if we fail to obtain adequate services such as transportation.

The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities and tanker transportation. If any pipelines or tankers become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport the oil and natural gas, which could increase our costs and/or reduce the revenues we might obtain from the sale of the oil and gas.

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. The amount of cash dividends, if any, to be paid in the future will depend on actions taken by our Board of Directors, as well as, our financial condition, results of operations, cash flows, levels of capital and exploration expenditures, future business prospects, expected liquidity needs, and other related matters that our Board of Directors deems relevant.

The loss of key members of our management team, or difficulty attracting and retaining experienced technical personnel, could reduce our competitiveness and prospects for future success.

The successful implementation of our strategies and handling of other issues integral to our future success will depend, in part, on our experienced management team. The loss of key members of our management team could have an adverse effect on our business. We do not carry key man insurance. 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 is 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

GENERAL 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, but not limited to, personal injury claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas 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, 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, with the possible exception of the Tronox Litigation discussed in *Note 17—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, the resolution of pending proceedings will not have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

In July 2013, Kerr-McGee Gathering LLC, one of the Company's consolidated subsidiaries, entered into a consent order with the Colorado Department of Public Health and Environment relating to the failure to comply with certain terms of permits at its Frederick compression station and agreed to pay a penalty of approximately $125,000.

In September 2013, Anadarko received a Notice of Proposed Penalty Assessment (Notice) from the Bureau of Safety and Environmental Enforcement (BSEE) as the result of an incident that occurred in February 2012 relating to a drilling rig in the Gulf of Mexico. In the Notice, the BSEE alleged several violations of certain offshore operational requirements and proposed a penalty in the amount of $395,000. Anadarko has disputed many of the allegations and is working with the BSEE to resolve this matter.

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, 2014, there were approximately 12,200 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 2013 and 2012:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2013				
Market Price				
High	**$ 89.20**	**$ 92.18**	**$ 96.75**	**$ 98.47**
Low	**$ 74.73**	**$ 78.30**	**$ 86.08**	**$ 73.60**
Dividends	**$ 0.09**	**$ 0.09**	**$ 0.18**	**$ 0.18**
2012				
Market Price				
High	$ 88.70	$ 79.85	$ 76.63	$ 76.95
Low	$ 75.90	$ 56.42	$ 64.19	$ 65.82
Dividends	$ 0.09	$ 0.09	$ 0.09	$ 0.09

The amount of future common stock dividends will depend on earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with its financial covenants, and other factors, and will be determined by the Board of Directors on a quarterly basis. For additional information, see *Liquidity and Capital Resources—Uses of Cash—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, 2013:

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	7,715,832	$ 63.30	25,581,734
Equity compensation plans not approved by security holders	—	—	—
Total	7,715,832	$ 63.30	25,581,734

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 2013:

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	Approximate dollar value of shares that may yet be purchased under the plans or programs
October	724	$ 93.08	—	
November	215,015	$ 91.34	—	
December	49,908	$ 88.46	—	
Fourth Quarter 2013	265,647	$ 90.80	—	$ —

(1) During the fourth quarter of 2013, all purchased shares related to stock received by the Company for the payment of withholding taxes due on employee stock plan share issuances.

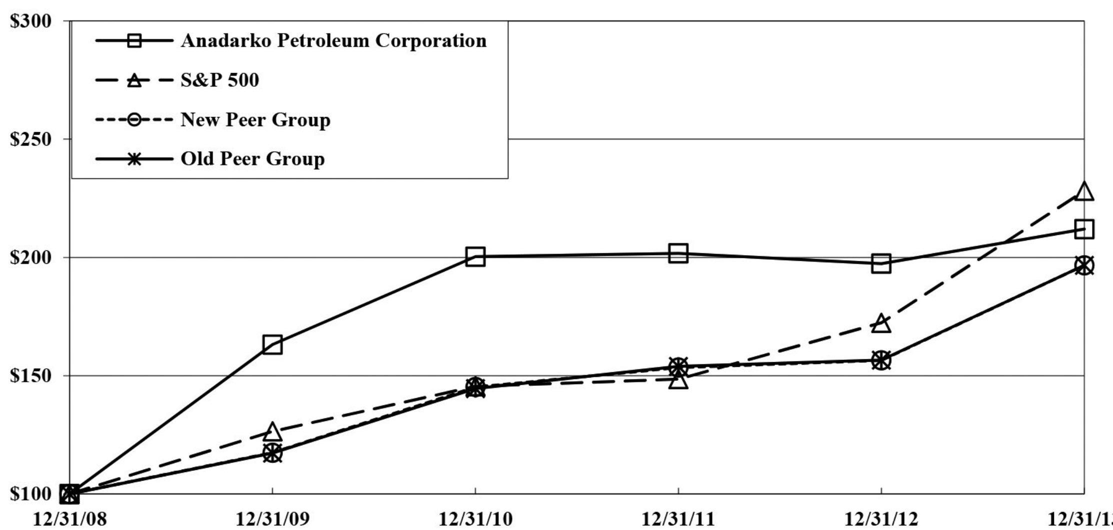
For additional information, see *Note 15—Share-Based Compensation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

PERFORMANCE GRAPH

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall 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 two peer groups. The 11 companies included in the new peer group (New Peer Group) are Apache Corporation; Chevron Corporation; ConocoPhillips; Devon Energy Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Murphy Oil Corporation; Noble Energy, Inc.; Occidental Petroleum Corporation; and Pioneer Natural Resources Company. The 10 companies included in the old peer group (Old Peer Group) are Apache 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. Plains Exploration and Production Company was excluded from the Old Peer Group since it was acquired in May 2013 and ceased trading. As a result, Murphy Oil Corporation was included in the New Peer Group for 2013.

Comparison of 5-Year Cumulative Total Return Among Anadarko Petroleum Corporation, the S&P 500 Index, the New Peer Group, and the Old 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 each of the peer groups on December 31, 2008, and its relative performance is tracked through December 31, 2013.

Fiscal Year Ended December 31	2008	2009	2010	2011	2012	2013
Anadarko Petroleum Corporation	$ 100.00	$ 163.18	$ 200.35	$ 201.75	$ 197.40	$ 211.99
S&P 500	100.00	126.46	145.51	148.59	172.37	228.19
New Peer Group	100.00	117.43	145.22	153.46	156.49	196.69
Old Peer Group	100.00	117.28	144.58	153.93	156.59	196.70

Item 6. Selected Financial Data

millions except per-share amounts	**2013**	2012	2011	2010	2009
	Summary Financial Information [1]				
Sales Revenues	**$ 14,867**	$ 13,307	$ 13,882	$ 10,842	$ 8,210
Gains (Losses) on Divestitures and Other, net	**(286)**	104	85	142	133
Reversal of Accrual for DWRRA Dispute	**—**	—	—	—	657
Total Revenues and Other	**14,581**	13,411	13,967	10,984	9,000
Algeria Exceptional Profits Tax Settlement	**33**	(1,797)	—	—	—
Deepwater Horizon Settlement and Related Costs	**15**	18	3,930	15	—
Operating Income (Loss)	**3,333**	3,727	(1,870)	1,769	377
Tronox-related Contingent Loss	**850**	(250)	250	—	—
Income (Loss)	**941**	2,445	(2,568)	821	(103)
Net Income (Loss) Attributable to Common Stockholders	**801**	2,391	(2,649)	761	(135)
Per Common Share (amounts attributable to common stockholders)					
Net Income (Loss)—Basic	**$ 1.58**	$ 4.76	$ (5.32)	$ 1.53	$ (0.28)
Net Income (Loss)—Diluted	**$ 1.58**	$ 4.74	$ (5.32)	$ 1.52	$ (0.28)
Dividends	**$ 0.54**	$ 0.36	$ 0.36	$ 0.36	$ 0.36
Average Number of Common Shares Outstanding—Basic	**502**	500	498	495	480
Average Number of Common Shares Outstanding—Diluted	**505**	502	498	497	480
Cash Provided by Operating Activities	**8,888**	8,339	2,505	5,247	3,926
Capital Expenditures	**$ 8,523**	$ 7,311	$ 6,553	$ 5,169	$ 4,558
Current Portion of Long-term Debt	**$ 500**	$ —	$ 170	$ 291	$ —
Long-term Debt	**13,065**	13,269	15,060	12,722	11,149
Midstream Subsidiary Note Payable to a Related Party	**—**	—	—	—	1,599
Total Debt	**$ 13,565**	$ 13,269	$ 15,230	$ 13,013	$ 12,748
Total Stockholders' Equity	**21,857**	20,629	18,105	20,684	19,928
Total Assets	**$ 55,781**	$ 52,589	$ 51,779	$ 51,559	$ 50,123
Annual Sales Volumes					
Natural Gas (Bcf)	**968**	913	852	829	809
Oil and Condensate (MMBbls)	**91**	86	79	74	68
Natural Gas Liquids (MMBbls)	**33**	30	27	23	17
Total (MMBOE)[2]	**285**	268	248	235	220
Average Daily Sales Volumes					
Natural Gas (MMcf/d)	**2,652**	2,495	2,334	2,272	2,217
Oil and Condensate (MBbls/d)	**248**	233	217	201	187
Natural Gas Liquids (MBbls/d)	**91**	83	74	63	47
Total (MBOE/d)	**781**	732	680	643	604
Proved Reserves					
Natural-Gas Reserves (Tcf)	**9.2**	8.3	8.4	8.1	7.8
Oil and Condensate Reserves (MMBbls)	**851**	767	771	749	733
Natural-Gas Liquids Reserves (MMBbls)	**407**	405	374	320	277
Total Proved Reserves (MMBOE)	**2,792**	2,560	2,539	2,422	2,304
Number of Employees	**5,700**	5,200	4,800	4,400	4,300

(1) Consolidated for Anadarko and its subsidiaries. Certain amounts for prior years have been reclassified to conform to the current presentation.
(2) Natural gas is converted to equivalent barrels at the rate of 6,000 cubic feet of gas per barrel.

Table of Measures

Bcf—Billion cubic feet

MMBbls—Million barrels

MMBOE—Million barrels of oil equivalent

MMcf/d—Million cubic feet per day

MBbls/d—Thousand barrels per day

MBOE/d—Thousand barrels of oil equivalent per day

Tcf—Trillion cubic feet

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 report in Item 8, and the information set forth in *Risk Factors* under Item 1A. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

OVERVIEW

Anadarko met or exceeded its key operational objectives in 2013. The Company increased sales volumes per day by approximately 7% over 2012 and added 528 million barrels of oil equivalent (BOE) of proved reserves. Additionally, the Company continued its deepwater exploration and appraisal drilling success with a 67% success rate in 2013. The Company ended 2013 with $3.7 billion of cash on hand, availability of its $5.0 billion senior secured revolving credit facility maturing in September 2015 ($5.0 billion Facility), and access to credit and capital markets as needed. Management believes that the Company is positioned to continue to satisfy its operational objectives and capital commitments with cash on hand, available borrowing capacity, and cash flows from operations.

Mission and Strategy

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 employs the following strategy to achieve this mission:

- explore in high-potential, proven basins
- identify and commercialize resources
- employ a global business development approach
- ensure financial discipline and flexibility

Exploring in high-potential, proven, and emerging basins worldwide provides the Company with growth opportunities. Anadarko's exploration success has created value by increasing future resource potential, while providing the flexibility to mitigate risk by monetizing discoveries.

Developing a portfolio of primarily unconventional resources provides the Company a stable base of capital-efficient and predictable development opportunities that, in turn, positions the Company for consistent growth at competitive rates.

Anadarko's global business development approach transfers core skills across the globe to assist in the discovery and development of world-class resources that are accretive to the Company's performance. These resources help form an optimized global portfolio where both surface and subsurface risks are actively managed.

A strong balance sheet is essential for the development of the Company's assets, and Anadarko is committed to disciplined investment in its businesses to efficiently manage commodity price cycles. Maintaining financial discipline enables the Company to capitalize on the opportunities afforded by its global portfolio, while allowing the Company to pursue new strategic growth opportunities.

Significant 2013 operating and financial activities include the following:

Overall

- Anadarko's full-year sales volumes averaged 781 thousand barrels of oil equivalent per day (MBOE/d), representing a 7% increase over 2012.
- Anadarko's liquids sales volumes were 339 thousand barrels per day (MBbls/d), representing a 7% increase over 2012, primarily due to increased sales volumes in the Wattenberg field, the Eagleford shale, and the East Texas/North Louisiana horizontal development.
- The Company achieved a 67% success rate from deepwater exploration and appraisal drilling in 2013.
- The Company recognized an $850 million contingent loss related to the Adversary Proceeding. See *Note 17—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

U.S. Onshore

- The Rocky Mountains Region (Rockies) full-year sales volumes averaged 327 MBOE/d, representing a 3% increase over 2012, primarily from the Wattenberg field.
- The Southern and Appalachia Region full-year sales volumes averaged 257 MBOE/d, representing a 30% increase over 2012, primarily from the Marcellus and Eagleford shales, and the East Texas/North Louisiana horizontal development.
- Anadarko acquired certain oil and gas properties and related assets in the Moxa area of Wyoming for $310 million.
- Anadarko exchanged certain oil and gas properties in the Wattenberg field with a third party, which allowed the Company to consolidate its working interest and operated acreage positions in the field.
- The Company sold its interest in the Pinedale/Jonah assets in the Rockies to a third party for $581 million in January 2014, recognizing a loss of $701 million in 2013.

Gulf of Mexico

- Gulf of Mexico full-year sales volumes averaged 96 MBOE/d, representing a 17% decrease from 2012, primarily due to natural production declines.
- The Company entered into a carried-interest arrangement that requires a third-party partner to fund $860 million of Anadarko's capital costs in exchange for a 12.75% working interest in the Heidelberg development.
- Anadarko's 80-MBbls/d Lucius spar was installed on location in the deepwater Gulf of Mexico and well-completion activities were initiated.
- The Company drilled three successful exploration wells and three appraisal wells.
- The Company increased its ownership position in the Coronado discovery from 15% to 35% and will assume operatorship following the drilling of an appraisal well, which was spud in the fourth quarter of 2013.

International

- International full-year sales volumes averaged 90 MBOE/d, representing a 7% increase from 2012, primarily in Ghana.
- The Company drilled two successful exploration wells in Mozambique.
- Anadarko and its partners continue to make progress marketing liquefied natural gas (LNG) to be produced from Anadarko-operated Rovuma Offshore Area 1 in Mozambique. The partners have reached non-binding Heads of Agreements for long-term LNG sales to buyers in Asian markets covering approximately two-thirds of the first 5-million-tonne-per-annum train.
- The Company participated in ten successful appraisal wells: six in Mozambique, two in Ghana, and two in Brazil.
- Anadarko and its partners achieved initial oil production at the El Merk project and production from the facility increased throughout the year as two oil trains and a natural-gas processing and NGLs extraction train were completed and brought online. Final commissioning of the NGLs extraction train is ongoing and will be completed in the first quarter of 2014.
- Anadarko and its partners received government approval for the Plan of Development for the Tweneboa/Enyenra/Ntomme (TEN) deepwater oil project offshore Ghana.
- Anadarko sold a 10% working interest in Rovuma Offshore Area 1 in Mozambique for $2.64 billion in February 2014.

Financial

- Anadarko's net income attributable to common stockholders for 2013 totaled $801 million, which included an $850 million contingent loss related to the Adversary Proceeding and $794 million of impairment expense primarily related to certain Gulf of Mexico properties and domestic onshore properties.
- The Company generated $8.9 billion of cash flow from operations in 2013, including $730 million related to the resolution of the Algeria exceptional profits tax dispute, and ended 2013 with $3.7 billion of cash on hand.
- Anadarko increased the quarterly dividend paid to its common stockholders from $0.09 per share to $0.18 per share.

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, 2013," refer to the comparison of the year ended December 31, 2013, to the year ended December 31, 2012. Similarly, any increases or decreases "for the year ended December 31, 2012," refer to the comparison of the year ended December 31, 2012, to the year ended December 31, 2011. The primary factors that affect the Company's results of operations include commodity prices for natural gas, crude oil, and natural gas liquids (NGLs); sales volumes; the Company's ability to discover additional reserves; the cost of finding such reserves; and operating costs.

RESULTS OF OPERATIONS

millions except per-share amounts and percentages	**2013**	2012	2011
Financial Results			
Natural-gas, oil and condensate, and NGLs sales	**$ 13,828**	$ 12,396	$ 12,834
Gathering, processing, and marketing sales	**1,039**	911	1,048
Gains (losses) on divestitures and other, net	**(286)**	104	85
Total revenues and other	**14,581**	13,411	13,967
Costs and expenses (1)	**11,248**	9,684	15,837
Other (income) expense (2)	**1,227**	162	1,554
Income tax expense (benefit)	**1,165**	1,120	(856)
Net income (loss) attributable to common stockholders	**$ 801**	$ 2,391	$ (2,649)
Net income (loss) per common share attributable to common stockholders—diluted	**$ 1.58**	$ 4.74	$ (5.32)
Average number of common shares outstanding—diluted	**505**	502	498
Operating Results			
Adjusted EBITDAX (3)	**$ 9,403**	$ 8,966	$ 8,869
Total proved reserves (MMBOE)	**2,792**	2,560	2,539
Annual sales volumes (MMBOE)	**285**	268	248
Capital Resources and Liquidity			
Cash provided by operating activities	**$ 8,888**	$ 8,339	$ 2,505
Capital expenditures	**8,523**	7,311	6,553
Total debt	**13,565**	13,269	15,230
Stockholders' equity	**$ 21,857**	$ 20,629	$ 18,105
Debt to total capitalization ratio	**38.3%**	39.1%	45.7%

MMBOE—million barrels of oil equivalent

(1) Includes Deepwater Horizon settlement and related costs of $15 million in 2013, $18 million in 2012, and $3.9 billion in 2011, and a credit of $1.8 billion for previously recognized expenses related to the favorable resolution of the Algeria exceptional profits tax dispute in 2012.

(2) Includes Tronox-related contingent loss of $850 million in 2013, reversal of the 2011 Tronox-related contingent loss $(250) million in 2012, and Tronox-related contingent loss of $250 million in 2011.

(3) See *Operating Results—Segment Analysis—Adjusted EBITDAX* for a description of Adjusted EBITDAX, which is not a U.S. Generally Accepted Accounting Principles (GAAP) measure, and for a reconciliation of Adjusted EBITDAX to income (loss) before income taxes, which is presented in accordance with GAAP.

FINANCIAL RESULTS

Sales Revenues and Volumes

millions except percentages	**2013**	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
Sales Revenues					
Natural-gas sales	**$ 3,388**	39%	$ 2,444	(26)%	$ 3,300
Oil and condensate sales	**9,178**	5	8,728	8	8,072
Natural-gas liquids sales	**1,262**	3	1,224	(16)	1,462
Total	**$ 13,828**	12	$ 12,396	(3)	$ 12,834

Anadarko's total sales revenues increased for the year ended December 31, 2013, primarily due to higher sales volumes for all products and higher average natural-gas prices, partially offset by lower average crude-oil and NGLs prices. Total sales revenues decreased for the year ended December 31, 2012, primarily due to lower average natural-gas and NGLs prices, partially offset by higher sales volumes for all products.

millions	**Natural Gas**	**Oil and Condensate**	**NGLs**	**Total**
2011 sales revenues	$ 3,300	$ 8,072	$ 1,462	$ 12,834
Changes associated with prices	(1,094)	9	(409)	(1,494)
Changes associated with sales volumes	238	647	171	1,056
2012 sales revenues	$ 2,444	$ 8,728	$ 1,224	$ 12,396
Changes associated with prices	**798**	**(85)**	**(82)**	**631**
Changes associated with sales volumes	**146**	**535**	**120**	**801**
2013 sales revenues	**$ 3,388**	**$ 9,178**	**$ 1,262**	**$ 13,828**

The following provides Anadarko's sales volumes for the years ended December 31, 2013, 2012, and 2011:

Sales Volumes	**2013**	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
Barrels of Oil Equivalent					
(MMBOE except percentages)					
United States	**252**	6%	237	9%	217
International	**33**	7	31	(2)	31
Total	**285**	6	268	8	248
Barrels of Oil Equivalent per Day					
(MBOE/d except percentages)					
United States	**691**	7%	648	9%	595
International	**90**	7	84	(2)	85
Total	**781**	7	732	8	680

Sales volumes represent actual production volumes adjusted for changes in commodity inventories. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K and *Other (Income) Expense—(Gains) Losses on Derivatives, net*. Production of natural gas, crude oil, and NGLs is usually not affected by seasonal swings in demand.

Natural-Gas Sales Volumes, Average Prices, and Revenues

	2013	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
United States					
Sales volumes—Bcf	**968**	6%	913	7%	852
MMcf/d	**2,652**	6	2,495	7	2,334
Price per Mcf	**$ 3.50**	31	$ 2.68	(31)	$ 3.87
Natural-gas sales revenues (millions)	**$ 3,388**	39	$ 2,444	(26)	$ 3,300

Bcf—billion cubic feet
MMcf/d—million cubic feet per day
Mcf—thousand cubic feet

The Company's natural-gas sales volumes increased 157 MMcf/d for the year ended December 31, 2013. Sales volumes for the Southern and Appalachia Region increased 246 MMcf/d primarily due to horizontal drilling and infrastructure expansions in the Eagleford and Marcellus shales, as well as new wells drilled in the liquids-rich East Texas/North Louisiana horizontal development. These increases were partially offset by lower sales volumes in the Gulf of Mexico of 47 MMcf/d primarily due to natural production declines. Also, sales volumes for the Rockies decreased 42 MMcf/d primarily due to a natural production decline in the Powder River basin, partially offset by higher sales volumes in the Wattenberg field due to increased horizontal drilling.

The Company's natural-gas sales volumes increased 161 MMcf/d for the year ended December 31, 2012, primarily due to higher sales volumes in the Southern and Appalachia Region of 220 MMcf/d as wells drilled in previous years were brought online through 2012 infrastructure expansions in the Eagleford and Marcellus shale and new wells were drilled in the liquids-rich East Texas/North Louisiana horizontal development. Also, the Company had higher sales volumes in the Rockies of 52 MMcf/d associated with drilling in the Greater Natural Buttes and the Wattenberg field. These increases were partially offset by reduced sales volumes in the Gulf of Mexico of 111 MMcf/d primarily due to natural production declines.

The average natural-gas price Anadarko received increased for the year ended December 31, 2013, as higher-than-normal residential and commercial demand early in the year reduced overall natural gas storage below the previous year's record levels. Natural-gas prices were further supported by higher demand in the fourth quarter of 2013, a reduction in natural-gas imports from Canada, and continued strength in exports to Mexico. Anadarko's average natural-gas price received decreased for the year ended December 31, 2012, due to continued growth in U.S. natural-gas production, reduced U.S. natural-gas demand as a result of mild winter temperatures, and above-average U.S. natural-gas storage levels in 2012.

Crude-Oil and Condensate Sales Volumes, Average Prices, and Revenues

	2013	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
United States					
Sales volumes—MMBbls	**58**	6%	55	14 %	48
MBbls/d	**158**	6	149	14	132
Price per barrel	**$ 97.02**	—	$ 97.46	—	$ 97.70
International					
Sales volumes—MMBbls	**33**	7%	31	(2)%	31
MBbls/d	**90**	7	84	(2)	85
Price per barrel	**$ 109.15**	(2)	$ 111.11	2	$ 109.20
Total					
Sales volumes—MMBbls	**91**	6%	86	8 %	79
MBbls/d	**248**	6	233	8	217
Price per barrel	**$ 101.41**	(1)	$ 102.35	—	$ 102.24
Oil and condensate sales revenues (millions)	**$ 9,178**	5	$ 8,728	8	$ 8,072

MMBbls—million barrels
MBbls/d—thousand barrels per day

Anadarko’s total crude-oil and condensate sales volumes increased 15 MBbls/d for the year ended December 31, 2013. Sales volumes for the Rockies increased 15 MBbls/d primarily in the Wattenberg field due to increased horizontal drilling. Sales volumes for the Southern and Appalachia Region increased 6 MBbls/d, as a result of horizontal drilling and infrastructure expansions in the Eagleford shale. Internationally, sales volumes increased 6 MBbls/d primarily in Ghana as a result of enhanced production due to successful acid stimulations and additional Phase 1A Jubilee wells brought online, as well as timing of cargo liftings. Sales volumes in the Gulf of Mexico decreased 10 MBbls/d primarily due to natural production declines.

Anadarko’s crude-oil and condensate sales volumes increased 16 MBbls/d for the year ended December 31, 2012. Increased horizontal drilling in the Wattenberg field led to a 9 MBbls/d sales-volume improvement in the Rockies. Horizontal drilling in the Eagleford shale and Bone Spring/Avalon formations also contributed to increased sales volumes in the Southern and Appalachia Region of 8 MBbls/d.

Anadarko’s average crude-oil price received decreased slightly for the year ended December 31, 2013, due to modestly lower international crude oil prices. Approximately 70% of Anadarko’s crude-oil sales volumes were based on prices that were either directly indexed to, or highly correlated to, Brent crude. Anadarko’s average crude-oil price received increased for the year ended December 31, 2012, primarily due to supply disruption concerns associated with political and civil unrest in the Middle East and North Africa, and steady global demand growth.

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

	2013	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
United States					
Sales volumes—MMBbls	**33**	10%	30	12%	27
MBbls/d	**91**	10	83	12	74
Price per barrel	**$ 37.97**	(6)	$ 40.44	(25)	$ 53.95
Natural-gas liquids sales revenues (millions)	**$ 1,262**	3	$ 1,224	(16)	$ 1,462

NGLs sales represent revenues from the sale of products derived from the processing of Anadarko's natural-gas production. The Company's NGLs sales volumes increased 8 MBbls/d for the year ended December 31, 2013. Sales volumes for the Southern and Appalachia Region increased 12 MBbls/d as a result of continued horizontal drilling and infrastructure expansion in the Eagleford shale and horizontal drilling in the liquids-rich East Texas/North Louisiana horizontal development. This increase was partially offset by lower sales volumes in the Rockies of 2 MBbls/d primarily due to ethane rejection in 2013, and in the Gulf of Mexico of 2 MBbls/d due to natural production declines.

Anadarko's NGLs sales volumes increased by 9 MBbls/d for the year ended December 31, 2012, as a result of drilling in liquids-rich areas, primarily in the Southern and Appalachia Region at the Eagleford shale and the East Texas/North Louisiana horizontal development.

Anadarko's average NGLs price received decreased for the year ended December 31, 2013, primarily due to lower market prices for ethane and butanes as a result of higher U.S. inventory and production levels. Anadarko's average NGLs price decreased for the year ended December 31, 2012, primarily due to lower market prices for ethane and propane. Ethane demand was reduced by down-time for maintenance and conversion upgrades at petrochemical facilities. Mild winter temperatures across much of the United States in 2011 reduced demand for propane and contributed to above-average levels of propane stockpiles.

Gathering, Processing, and Marketing Margin

millions except percentages	2013	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
Gathering, processing, and marketing sales	**$ 1,039**	14%	$ 911	(13)%	$ 1,048
Gathering, processing, and marketing expense	**869**	14	763	(4)	791
Gathering, processing, and marketing margin	**$ 170**	15	$ 148	(42)	$ 257

Marketing margins represent the margin earned by purchasing and selling third-party oil and natural gas. Processing margin represents the margin earned by purchasing third-party natural gas and selling the extracted NGLs and remaining residue gas. The Company also earns gathering revenue and processing fees by providing gathering and processing services to third parties. Operating and transportation expenses relate to the Company's costs to perform these activities, excluding the purchase of commodities that are included in the margin.

For the year ended December 31, 2013, the gathering, processing, and marketing margin increased $22 million. This increase was primarily due to higher gathering revenue as a result of increased throughput across several of Anadarko's gathering systems and higher marketing margins, partially offset by increased transportation expenses due to increased third-party volumes and increased demand fees.

For the year ended December 31, 2012, the gathering, processing, and marketing margin decreased $109 million primarily due to lower commodity prices, which led to reduced natural-gas processing margins and decreased marketing margins, and higher transportation expenses primarily due to higher demand fees. This decrease was partially offset by additional revenues earned and expenses incurred for midstream assets acquired in February 2011 and May 2011, and an increase in gathering and processing revenues associated with increased throughput volumes across several of Anadarko's fee-based systems.

Gains (Losses) on Divestitures and Other, net

Gains (losses) on divestitures and other, net decreased $390 million primarily due to losses on divestitures in 2013. In the fourth quarter of 2013, the Company recognized losses on assets held for sale of $704 million, primarily associated with the divestiture of the Pinedale/Jonah assets in the Rockies, which closed in January 2014 for sale proceeds of $581 million. This decrease was partially offset by a $140 million gain in 2013 associated with the Company's divestiture of its interests in a soda ash joint venture. The Company divested its interests in the soda ash joint venture for $310 million and potential additional consideration based on future revenue of the joint venture, while retaining its royalty interest in soda ash mined by the joint venture from the Company's Land Grant. In 2013, gains on divestitures also included $94 million primarily related to the divestiture of certain oil and gas properties in the United States compared to net losses on similar divestitures of $71 million in 2012 primarily related to the sale of oil and gas properties in Indonesia. See *Note 2—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 on assets held for sale.

For the year ended December 31, 2012, gains (losses) on divestitures and other, net increased $19 million primarily due to increased mineral revenue of $36 million related to increased mining of soda ash on Anadarko's Land Grant and higher per-ton average sales prices. Increased mineral revenue was partially offset by an increase in net losses on divestitures of $17 million. Gains (losses) on divestitures for 2012 included net losses of $71 million, as discussed above. Gains (losses) on divestitures for 2011 included net losses of $54 million primarily related to write-downs of $422 million of assets held for sale. In 2011, the Company began marketing certain domestic properties from the oil and gas exploration and production reporting segment and the midstream reporting segment in order to redirect its operating activities and capital investment to other areas. Also included in 2011 was a $76 million loss that occurred in connection with the Company's purchase of the Wattenberg Plant. These losses were partially offset by 2011 gains of $419 million for receipt and final settlement of contingent consideration related to the 2008 divestiture of its interest in the Peregrino field offshore Brazil and $21 million from the acquisition-date fair-value remeasurement of the Company's pre-acquisition 7% equity interest in the Wattenberg Plant.

Costs and Expenses

	2013	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
Oil and gas operating (millions)	**$ 1,092**	12%	$ 976	(2)%	$ 993
Oil and gas operating—per BOE	**3.83**	5	3.65	(9)	4.00
Oil and gas transportation and other (millions)	**1,022**	7	955	7	891
Oil and gas transportation and other—per BOE	**3.59**	1	3.57	(1)	3.59

For the year ended December 31, 2013, oil and gas operating expenses increased $116 million primarily due to increased workovers in the Gulf of Mexico, Rockies, and Southern and Appalachia Regions; higher expenses in Algeria associated with the start of El Merk production in 2013; and increased costs associated with increased activity in the Rockies and Southern and Appalachia Regions. Oil and gas operating expenses per BOE increased by $0.18 for the year ended December 31, 2013, primarily due to these higher costs, partially offset by increased sales volumes.

For the year ended December 31, 2012, oil and gas operating expenses decreased by $17 million primarily due to lower workover expenses of $67 million as a result of fewer workovers primarily in the Gulf of Mexico and the Rockies, partially offset by $52 million of higher operating expenses from increased activity in Ghana. Per-BOE oil and gas operating expenses decreased by $0.35 for the year ended December 31, 2012, primarily as a result of increased sales volumes, while production costs remained flat as a result of efficiency gains, and lower workover expenses as discussed above.

Oil and gas transportation and other expenses increased by $67 million for the year ended December 31, 2013, and $64 million for the year ended December 31, 2012, primarily due to higher gas-gathering and transportation costs attributable to higher volumes and increased costs related to growth in the Company's U.S. onshore asset base. Oil and gas transportation and other expenses per BOE increased by $0.02 for the year ended December 31, 2013, primarily due to the higher costs discussed above, partially offset by increased sales volumes. Oil and gas transportation and other expenses per BOE decreased by $0.02 for the year ended December 31, 2012, primarily due to increased sales volumes, partially offset by the higher costs discussed above.

millions	**2013**	2012	2011
Exploration Expense			
Dry hole expense	**$ 556**	$ 440	$ 154
Impairments of unproved properties	**308**	1,104	471
Geological and geophysical expense	**208**	151	246
Exploration overhead and other	**257**	251	205
Total exploration expense	**$ 1,329**	$ 1,946	$ 1,076

Exploration expense decreased $617 million for the year ended December 31, 2013. Impairments of unproved properties decreased $796 million primarily due to $845 million of 2012 impairments, which included $721 million related to Powder River coalbed methane properties primarily due to lower natural-gas prices and $124 million related to a Gulf of Mexico natural-gas property that the Company does not expect to develop under the forecasted natural-gas price environment. In addition, unproved property impairments for the year ended December 31, 2013, decreased by $144 million as a result of a change in the Company's estimated success rate associated with unproved Gulf of Mexico properties. The decrease was partially offset by unproved oil and gas property impairments in 2013 due to changes to the Company's drilling plans, which included $89 million for an unproved property in Block 43/11 in the South China Sea, $53 million for an unproved property in the Espírito Santo basin in Brazil, and $53 million for a domestic onshore unproved property. For the year ended December 31, 2013, dry hole expense increased by $116 million primarily due to 2013 dry hole expense for wells in the Gulf of Mexico, Sierra Leone, Kenya, Côte d'Ivoire, and New Zealand, partially offset by 2012 dry hole expense for wells in Brazil, Sierra Leone, the Gulf of Mexico, Ghana, and Côte d'Ivoire. Geological and geophysical expense increased $57 million for the year ended December 31, 2013, primarily due to 2013 seismic purchases in Colombia and the Gulf of Mexico.

Exploration expense increased $870 million for the year ended December 31, 2012. Impairments of unproved properties increased $633 million primarily due to $845 million of 2012 impairments for certain unproved properties in the Rockies and the Gulf of Mexico as discussed above, partially offset by 2011 impairments of certain unproved properties in the Gulf of Mexico of $124 million and Indonesia of $63 million due to decreases in the estimated recoverable cash flows. Dry hole expense increased $286 million for the year ended December 31, 2012, primarily due to wells in Brazil, Sierra Leone, Côte d'Ivoire, Mozambique, and the Gulf of Mexico. Geological and geophysical expense decreased $95 million primarily due to fewer seismic purchases in Kenya, Liberia, New Zealand, and Mozambique. Exploration overhead and other increased $46 million for the year ended December 31, 2012, primarily due to increased exploration activity in U.S. onshore and Mozambique.

millions except percentages	**2013**	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
General and administrative	**$ 1,090**	(13)%	$ 1,246	18%	$ 1,060
Depreciation, depletion, and amortization	**3,927**	(1)	3,964	3	3,830
Other taxes	**1,077**	(12)	1,224	(18)	1,492
Impairments	**794**	104	389	(78)	1,774

For the year ended December 31, 2013, general and administrative (G&A) expense decreased by $156 million due to reduced legal-related expenses of $101 million and lower employee-related expenses of $60 million. The reduced legal-related expenses were primarily related to lower Tronox legal expenses in 2013 and the third-party reimbursement during 2013 of the Company's legal expenses associated with the Algeria exceptional profits tax settlement. The lower employee-related expenses were primarily related to the 2012 expense associated with Unit Appreciation Rights (UARs), partially offset by higher 2013 employee-related expenses associated with operational expansions. The UARs were awarded in prior years to certain officers of the general partner of Western Gas Partners, LP (WES), a consolidated subsidiary of Anadarko, pursuant to the Western Gas Holdings, LLC (WGH) Equity Incentive Plan. This expense was related to the change in fair value of the UARs upon the initial public offering (IPO) of Western Gas Equity Partners, LP (WGP), a consolidated subsidiary formed to own substantially all of Anadarko's partnership interests in WES. For the year ended December 31, 2012, G&A expense increased by $186 million due to higher employee-related expenses of $150 million primarily related to expense associated with the UARs discussed above and $41 million due to legal-related expenses primarily related to increased Tronox legal expenses in 2012.

For the year ended December 31, 2013, depreciation, depletion, and amortization (DD&A) expense decreased by $37 million primarily due to accelerated expense in 2012 associated with the depletion of fields in the Gulf of Mexico, partially offset by higher volumes in 2013. For the year ended December 31, 2012, DD&A expense increased by $134 million primarily due to higher sales volumes, accelerated expense in 2012 as discussed above, and the start of production at Caesar/Tonga in March 2012. These increases were partially offset by lower per-barrel DD&A rates resulting from asset impairments recognized in the fourth quarter of 2011 and reserves additions in 2012 in the Southern and Appalachia Region.

For the year ended December 31, 2013, other taxes decreased by $147 million primarily related to lower Algerian exceptional profits taxes of $116 million due to a lower Algeria effective tax rate resulting from the resolution of the Algeria exceptional profits tax dispute and lower crude-oil prices. In addition, lower sales volumes and crude-oil prices resulted in a $33 million decrease in U.S. production and severance taxes primarily in Alaska. For the year ended December 31, 2012, other taxes decreased by $268 million primarily related to lower Algeria exceptional profits taxes of $184 million due to a lower Algeria effective tax rate resulting from the resolution of the Algeria exceptional profits tax dispute. Other taxes also decreased due to lower commodity prices, which resulted in lower U.S. production and severance taxes of $55 million, and lower ad valorem taxes of $27 million.

Impairment expense of $794 million for the year ended December 31, 2013, included $562 million due to a reduction in estimated future net cash flows per barrel and downward revisions of reserves for certain Gulf of Mexico properties that the Company no longer plans to develop. In addition, impairment expense included $142 million for certain domestic onshore oil and gas properties due to downward revisions of reserves that the Company no longer plans to develop and $49 million for related midstream assets. Impairment expense also included $30 million for certain midstream properties due to a reduction in estimated future cash flows, and $11 million related to the Company's Venezuelan cost-method investment due to declines in estimated recoverable value. Declines in commodity prices or negative reserves revisions could result in additional impairments. 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.

Impairment expense was $389 million for the year ended December 31, 2012. The Company recognized impairments of $363 million related to oil and gas exploration and production reporting segment properties located in the United States, $13 million related to midstream properties, and $13 million related to the Company's Venezuelan cost-method investment. Impairment expense for U.S. oil and gas exploration and production reporting segment properties included $259 million related to lower natural-gas prices. Impairment expense for U.S. properties also included $79 million related to downward reserves revisions for a Gulf of Mexico property that was near the end of its economic life and $25 million for a platform in the Gulf of Mexico.

Impairment expense of $1.8 billion for the year ended December 31, 2011, included $1.2 billion related to oil and gas exploration and production reporting segment properties located in the United States, $458 million for midstream reporting segment properties, and $91 million related to the Company's Venezuelan cost-method investment. Impairment expense of $952 million for U.S. onshore oil and gas properties and $446 million for associated midstream properties was triggered by lower natural-gas prices. Impairment expense also included $162 million for certain Gulf of Mexico properties related to declines in estimated recoverable reserves, and $100 million related to onshore properties due to changes in projected cash flows resulting from the Company's intent to divest of the properties.

millions	**2013**	2012	2011
Algeria exceptional profits tax settlement	**$ 33**	$ (1,797)	$ —
Deepwater Horizon settlement and related costs	**15**	18	3,930

In March 2012, Anadarko and Sonatrach resolved the exceptional profits tax dispute. The resolution provided for delivery to the Company of crude oil valued at $1.7 billion and the elimination of $62 million of previously recorded and unpaid transportation charges. The Company recognized a $1.8 billion credit in the Costs and Expenses section of the Consolidated Statement of Income for 2012 to reflect the effect of this agreement for previously recorded expenses. During 2013, the Company revised its estimate of income tax expense related to the elimination of previously recorded and unpaid transportation charges and recognized a $33 million unfavorable adjustment to the settlement, which was offset by an equivalent income tax benefit also recognized in 2013. At December 31, 2013, the Company had collected all of the $1.7 billion associated with the Algeria exceptional profits tax receivable.

In October 2011, the Company and BP Exploration & Production Inc (BP) entered into the Settlement Agreement, under which the Company paid $4.0 billion in cash and transferred its interest in the Macondo well and the Mississippi Canyon Block 252 lease to BP, and BP agreed to accept this consideration in full satisfaction of its claims against Anadarko. Refer to *Note 17—Contingencies—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion and analysis of these events.

Deepwater Horizon settlement and related costs included legal expenses and related costs associated with the Deepwater Horizon events of $15 million for the year ended December 31, 2013, and $18 million for the year ended December 31, 2012. For the year ended December 31, 2011, Deepwater Horizon settlement and related costs included a $4.0 billion expense for the Company's cash payment made to BP pursuant to the Settlement Agreement discussed above, as well as $93 million of legal expenses and other related costs associated with the Deepwater Horizon events. These amounts were partially offset by a $163 million gain recognized in 2011 for insurance recoveries associated with the Deepwater Horizon events. Although Anadarko has been indemnified by BP for certain costs, the Company may be required to recognize a liability for amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recorded by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c. Additionally, as part of the Settlement Agreement, BP has agreed that, to the extent it receives value in the future from claims that it has asserted or could assert against third parties arising from or relating to the Deepwater Horizon events, it will make cash payments (not to exceed $1.0 billion in the aggregate) to Anadarko, on a current and continuing basis, equal to 12.5% of the aggregate value received by BP in excess of $1.5 billion. Any payments received by the Company pursuant to this arrangement will be accounted for as a reimbursement of the $4.0 billion 2011 payment made to BP as part of the Settlement Agreement.

Other (Income) Expense

millions except percentages	**2013**	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
Interest Expense					
Current debt, long-term debt, and other	**$ 949**	(1)%	$ 963	(2)%	$ 986
Capitalized interest	**(263)**	(19)	(221)	(50)	(147)
Interest expense	**$ 686**	(8)	$ 742	(12)	$ 839

Anadarko's interest expense decreased by $56 million for the year ended December 31, 2013, primarily due to an increase in capitalized interest of $42 million related to higher construction-in-progress balances for long-term capital projects. Additionally, interest expense for the year ended December 31, 2013, decreased $31 million as a result of the repayment of outstanding borrowings during 2012 associated with the five-year, $5.0 billion Facility. The decrease for the year ended December 31, 2013, was partially offset by $18 million of interest expense for outstanding borrowings primarily related to WES's 4.000% Senior Notes due 2022. For additional information, see *Liquidity and Capital Resources* and *Interest-Rate Risk* under Item 7A of this Form 10-K.

Anadarko's interest expense decreased by $97 million for the year ended December 31, 2012, primarily due to an increase in capitalized interest of $74 million related to higher construction-in-progress balances for long-term capital projects. Additionally, interest expense for the year ended December 31, 2012, decreased by $32 million as a result of interest incurred during 2011 related to the Company's capital lease obligations for a floating production, storage, and offloading vessel (FPSO) for the Company's Jubilee field operations in Ghana. In December 2011, the Company and its partners in the Jubilee project purchased the vessel, resulting in cancellation of the capital lease obligation.

millions	**2013**	2012	2011
(Gains) Losses on Derivatives, net			
(Gains) losses on commodity derivatives, net	**$ 141**	$ (387)	$ (562)
(Gains) losses on interest-rate and other derivatives, net	**(539)**	61	1,023
(Gains) losses on derivatives, net	**$ (398)**	$ (326)	$ 461

(Gains) losses on derivatives, net represents the changes in fair value of the Company's derivative instruments. Anadarko enters into commodity derivatives to manage the risk of changes in the market prices for its anticipated sales of production and enters into interest-rate swaps to fix or float interest rates on existing or anticipated indebtedness to manage exposure to unfavorable interest-rate changes. For additional information, see *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

millions except percentages	**2013**	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
Other (Income) Expense, net					
Interest income	**$ (19)**	19%	$ (16)	(24)%	$ (21)
Other	**108**	NM	12	52	25
Total other (income) expense, net	**$ 89**	NM	$ (4)	NM	$ 4

NM—not meaningful

Total other income decreased by $93 million for the year ended December 31, 2013. In 2013, as a result of a bankruptcy declaration by a third party, the U.S. Department of the Interior ordered Anadarko to decommission offshore wells and production facilities previously sold to the third party and not related to the Company's current operations. During 2013, the Company recognized a decommissioning charge of $117 million. Anadarko expects to complete decommissioning of the production facilities in 2014 and the wells in 2015. Also, the Company was previously notified that, as a result of a prior acquisition, it is one of 27 potentially responsible parties with respect to a landfill located in California and recorded a restoration liability of $50 million in 2013. These decreases to other income were partially offset by the 2013 reversal of the $56 million tax indemnification liability associated with the 2006 sale of the Company's Canadian subsidiary. The indemnity was reversed as a result of certain Canadian tax legislative changes.

Total other income increased $8 million for the year ended December 31, 2012, due to changes in foreign-currency gains/losses. These gains/losses reflected the impact of exchange-rate changes primarily applicable to foreign currency held in escrow pending final determination of the Company's Brazilian tax liability attributable to the 2008 divestiture of the Peregrino field offshore Brazil.

millions	**2013**	2012	2011
Tronox-related contingent loss	**$ 850**	$ (250)	$ 250

During 2013, the Company recognized an $850 million contingent loss related to the Adversary Proceeding. During 2012, the Company reversed the $250 million Tronox-related contingent loss recognized in 2011. See *Note 17—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Income Tax Expense

millions except percentages	**2013**	2012	2011
Income tax expense (benefit)	**$ 1,165**	$ 1,120	$ (856)
Effective tax rate	**55%**	31%	25%

The increase from the 35% U.S. federal statutory rate for the year ended December 31, 2013, was primarily attributable to the tax impact from foreign operations, non-deductible Algerian exceptional profits tax, and deferred tax adjustments.

The decrease from the 35% U.S. federal statutory rate for the year ended December 31, 2012, was primarily attributable to the non-taxable resolution of the Algeria exceptional profits tax dispute. This amount was partially offset by the tax impact from foreign operations and non-deductible Algerian exceptional profits tax.

The Company reported a loss before income taxes for the year ended December 31, 2011. As a result, items that ordinarily increase or decrease the tax rate will have the opposite effect. The decrease from the 35% U.S. federal statutory rate for the year ended December 31, 2011, was primarily attributable to non-deductible Algerian exceptional profits tax, the tax impact from foreign operations, and items resulting from business acquisitions and other items. These amounts were partially offset by state income tax benefits of the loss.

For additional information on income tax rates, see *Note 19—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Net Income Attributable to Noncontrolling Interests

The Company's net income attributable to noncontrolling interests of $140 million for the year ended December 31, 2013, $54 million for 2012, and $81 million for 2011, related to public ownership interests in WES for all periods and WGP for 2013 and 2012. Public ownership of WES was 56.4% at December 31, 2013, 51.8% at December 31, 2012, and 54.7% at December 31, 2011. In December 2012, WGP completed its IPO of approximately 20 million common units representing limited partner interests in WGP at a price of $22.00 per common unit. Public ownership of WGP was 9.0% at December 31, 2013 and 2012. See *Note 9—Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

OPERATING RESULTS

Segment Analysis—Adjusted EBITDAX 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; exploration expense; DD&A; impairments; interest expense; total (gains) losses on derivatives, net, less net cash received in settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income attributable to noncontrolling interests. During the periods presented, certain items not related to the Company's normal operations included Deepwater Horizon settlement and related costs, Algeria exceptional profits tax settlement, Tronox-related contingent loss, and certain other nonoperating items included in other (income) expense, net. The Company's definition of Adjusted EBITDAX, which is not a GAAP measure, excludes exploration expense, as it is not an indicator of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, 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 received in 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 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.

Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders. Adjusted EBITDAX, as defined by Anadarko, may not be comparable to similarly titled measures used by other companies. Therefore, Anadarko's consolidated Adjusted EBITDAX should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures prepared in accordance with GAAP, such as operating income or cash flows from operating activities. Adjusted EBITDAX has important limitations as an analytical tool because it excludes certain items that affect net income (loss) attributable to common stockholders and net cash provided by operating activities. Adjusted EBITDAX should not be considered in isolation or as a substitute for an analysis of Anadarko's results as reported under GAAP. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes, and consolidated Adjusted EBITDAX by reporting segment.

Adjusted EBITDAX

millions except percentages	**2013**	Inc/(Dec) vs. 2012	2012	Inc/(Dec) vs. 2011	2011
Income (loss) before income taxes	**$ 2,106**	(41)%	$ 3,565	NM	$ (3,424)
Exploration expense	**1,329**	(32)	1,946	81%	1,076
DD&A	**3,927**	(1)	3,964	3	3,830
Impairments	**794**	104	389	(78)	1,774
Interest expense	**686**	(8)	742	(12)	839
Total (gains) losses on derivatives, net, less net cash received in settlement of commodity derivatives	**(307)**	(169)	443	(34)	675
Deepwater Horizon settlement and related costs	**15**	(17)	18	(100)	3,930
Algeria exceptional profits tax settlement	**33**	102	(1,797)	NM	—
Tronox-related contingent loss	**850**	NM	(250)	NM	250
Certain other nonoperating items	**110**	NM	—	NM	—
Less net income attributable to noncontrolling interests	**140**	159	54	(33)	81
Consolidated Adjusted EBITDAX	**$ 9,403**	5	$ 8,966	1	$ 8,869
Adjusted EBITDAX by segment					
Oil and gas exploration and production	**$ 9,238**	9	$ 8,500	(3)	$ 8,787
Midstream	**508**	7	474	13	419
Marketing	**(125)**	(20)	(104)	(65)	(63)
Other and intersegment eliminations	**(218)**	NM	96	135	(274)

Oil and Gas Exploration and Production The increase in Adjusted EBITDAX for the year ended December 31, 2013, was primarily due to higher sales volumes for all products and higher natural-gas prices, partially offset by lower crude-oil and NGLs prices and losses on divestitures primarily related to the Pinedale/Jonah assets in the Rockies. The decrease in Adjusted EBITDAX for the year ended December 31, 2012, was primarily due to lower NGLs and natural-gas prices, partially offset by higher sales volumes.

Midstream The increase in Adjusted EBITDAX for the year ended December 31, 2013, was primarily due to higher gathering revenue as a result of increased throughput across several of Anadarko's gathering systems. For the year ended December 31, 2012, the increase in Adjusted EBITDAX resulted from additional operating income from assets acquired in February 2011 and May 2011, and an increase in gathering and processing revenues associated with increased throughput across several of Anadarko's fee-based systems. This increase was partially offset by lower commodity prices, which led to reduced natural-gas processing margins.

Marketing Marketing earnings primarily represent the margin earned on sales of natural gas, oil, and NGLs purchased from third parties. The decrease in Adjusted EBITDAX for the year ended December 31, 2013, resulted from higher transportation expenses due to increased third-party volumes and increased demand fees, partially offset by higher margins primarily associated with natural-gas and NGLs sales. The decrease in Adjusted EBITDAX for the year ended December 31, 2012, resulted from lower margins as a result of lower sales prices and increased transportation expenses primarily due to higher demand fees.

Other and Intersegment Eliminations Other and intersegment eliminations consists primarily of corporate costs, income from hard minerals investments and royalties, and net cash received in settlement of commodity derivatives. The decrease in Adjusted EBITDAX for the year ended December 31, 2013, was primarily due to a decrease in net cash received in settlement of commodity derivatives in 2013, partially offset by 2012 expense associated with the change in the fair value of the general partner UARs in connection with the WGP IPO. The UARs were awarded in prior years to certain officers of the general partner of WES, pursuant to the WGH Equity Incentive Plan. The increase in Adjusted EBITDAX for the year ended December 31, 2012, was primarily due to an increase in net cash received in settlement of commodity derivatives in 2012, partially offset by the 2012 expense associated with general partner UARs discussed above.

Proved Reserves Anadarko is focused on growth and profitability, and reserves replacement is a key to growth. Future profitability partially depends on commodity prices and the cost of finding and developing oil and gas reserves. Reserves growth can be achieved through successful exploration and development drilling, improved recovery, or acquisition of producing properties.

Additional reserves information is contained in the *Supplemental Information on Oil and Gas Exploration and Production Activities (Supplemental Information)* under Item 8 of this Form 10-K.

MMBOE	**2013**	2012	2011
Proved Reserves			
Beginning of year	**2,560**	2,539	2,422
Reserves additions and revisions			
Discoveries and extensions	**145**	82	174
Infill-drilling additions [1]	**410**	383	203
Drilling-related reserves additions and revisions	**555**	465	377
Other non-price-related revisions [1]	**(40)**	(31)	7
Net organic reserves additions	**515**	434	384
Acquisition of proved reserves in place	**36**	4	—
Price-related revisions [1]	**(23)**	(68)	8
Total reserves additions and revisions	**528**	370	392
Sales in place	**(12)**	(81)	(29)
Production	**(284)**	(268)	(246)
End of year	**2,792**	2,560	2,539
Proved Developed Reserves			
Beginning of year	**1,883**	1,811	1,673
End of year	**2,003**	1,883	1,811

(1) Combined and reported as revisions of prior estimates in the Company's *Supplemental Information* under Item 8 of this Form 10-K.

Proved Reserves Additions and Revisions During 2013, the Company added 528 MMBOE of proved reserves as a result of additions (purchases in place, discoveries, and extensions) and revisions. The Company expects the majority of future reserves growth to come from revisions associated with infill drilling (reserves bookings related to infill wells are treated as positive revisions due to increases in expected recovery), extensions of current fields, new discoveries in U.S. onshore and the Gulf of Mexico, successful exploration in international growth areas, and purchases of properties in strategic areas.

Additions During 2013, Anadarko added 145 MMBOE of proved reserves through extensions and discoveries primarily as a result of successful drilling in the Marcellus shale and the Gulf of Mexico. Although shale plays represent only about 13% of the Company's total proved reserves at December 31, 2013, growth in the shale plays contributed 70 MMBOE, or 48%, of the total extensions and discoveries. In addition, Anadarko added 36 MMBOE of developed reserves through acquisition activities almost exclusively in the Rockies. During 2012, Anadarko added 82 MMBOE of proved reserves primarily as a result of successful drilling in the Marcellus shale and the Gulf of Mexico. Shale plays contributed 66 MMBOE of the total extensions and discoveries in 2012. During 2011, Anadarko added 174 MMBOE of proved reserves primarily as a result of successful drilling in the Marcellus and Eagleford shales and the Gulf of Mexico. Shale plays contributed 119 MMBOE of the 2011 additions.

Revisions Total revisions in 2013 resulted in an increase of 347 MMBOE, or 14%, of the beginning-of-year reserves base. Total revisions include the effects of new infill drilling, changes in commodity prices and other updates reflecting changes in economic conditions, changes in reservoir performance, and changes in development plans. Total 2013 revisions included an increase of 410 MMBOE related to successful infill drilling, primarily in large onshore areas such as Wattenberg, Greater Natural Buttes, and the Eagleford shale and 30 MMBOE resulting from improved oil and natural-gas prices. Partially offsetting these positive revisions were decreases of 53 MMBbls of NGLs reserves due to lower ethane prices and 40 MMBOE due to other non-price-related revisions primarily in the Rockies. Total revisions in 2012 were 284 MMBOE or 11% of the beginning-of-year reserves base. Total 2012 revisions included an increase of 383 MMBOE related to successful infill drilling, primarily in Greater Natural Buttes, Wattenberg, and Carthage, and 33 MMBOE resulting from the resolution of the Algeria exceptional profits tax dispute. Partially offsetting these positive revisions were decreases of 68 MMBOE due to lower commodity prices, 56 MMBOE at Wattenberg primarily due to removing reserves associated with the discontinued vertical drilling program, and 8 MMBOE from all other assets. Total revisions in 2011 were 218 MMBOE or 9% of the beginning-of-year reserves base. The revisions included an increase of 203 MMBOE related to the continuation of successful infill drilling in large onshore areas, including Greater Natural Buttes, Wattenberg, and Pinedale fields; 182 MMBOE of positive revisions to prior estimates; and 8 MMBOE associated with higher oil prices. These positive revisions were partially offset by the transfer of 175 MMBOE of proved reserves to unproved categories as a result of changes to development plans and economic conditions experienced during 2011.

Sales in Place In 2013, the Company sold U.S. properties or interests in U.S. properties containing 12 MMBOE of proved undeveloped reserves. Sales were almost exclusively associated with a partial sale of a working interest in the Gulf of Mexico Heidelberg development project. In 2012, the Company sold U.S. properties or interests in U.S. properties containing 59 MMBOE of proved developed reserves and 22 MMBOE of proved undeveloped reserves. Sales included a portion of the Company's working interests in the Rockies Salt Creek enhanced oil recovery project and the Gulf of Mexico Lucius development project, and asset divestitures in South Texas, West Texas, the Gulf of Mexico, the Rockies, and North Louisiana. In 2011, the Company sold U.S. properties containing 7 MMBOE of proved developed reserves and 22 MMBOE of proved undeveloped reserves. This included a transaction in the Maverick basin and asset divestitures in South Texas and Alaska.

Discounted Future Net Cash Flows At December 31, 2013, the discounted (at 10%) estimated future net cash flows from Anadarko's proved reserves was $29.1 billion (measured in accordance with the regulations of the Securities and Exchange Commission (SEC) and the Financial Accounting Standards Board (FASB)). This amount was calculated based on the 12-month average beginning-of-month prices for the year, held flat for the life of the reserves, adjusted for any contractual provisions. See *Supplemental Information* under Item 8 of this Form 10-K.

The present value of future net cash flows is not an estimate of the fair value of Anadarko's proved reserves. 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.

LIQUIDITY AND CAPITAL RESOURCES

Overview Anadarko generates cash needed to fund capital expenditures, debt-service obligations, and dividend payments primarily from operating activities, and enters into debt and equity transactions to maintain its desired capital structure and to finance acquisition opportunities. Liquidity may also be enhanced through asset divestitures and joint ventures that reduce future capital expenditures. In addition, as of January 2014, an effective registration statement is available to Anadarko, covering the resale of up to 40 million WGP common units. These common units were issued to Anadarko in connection with WGP's IPO in December 2012.

During 2013, the primary source for funding of capital investments was cash flows from operating activities. In addition, the Company collected the remaining $730 million of the Algeria exceptional profits tax settlement. The Company continuously monitors its liquidity needs, coordinates its capital expenditure program with its expected cash flows and projected debt-repayment schedule, and evaluates available funding alternatives in light of current and expected conditions.

At December 31, 2013, Anadarko's scheduled 2014 debt maturities were $775 million. Anadarko's $275 million aggregate principal amount of 5.750% Senior Notes due June 2014 and Zero-Coupon Senior Notes due 2036 (Zero Coupons), which can be put to the Company in October 2014 (the next potential put date) for up to the then-accreted value of $756 million, are classified as long-term debt on the Company's Consolidated Balance Sheets, as the Company has the ability and intent to refinance these obligations using long-term debt. There are no scheduled debt maturities in 2015, exclusive of the Zero Coupons. The Company has a variety of funding sources available, including cash on hand, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through divestitures and joint-venture arrangements, and the Company's $5.0 billion Facility. Management believes that the Company's liquidity position, asset portfolio, and continued strong operating and financial performance provide the necessary financial flexibility to fund the Company's current and long-term operations.

Effects of Tronox Adversary Proceeding on Liquidity During 2013, the Company recorded an $850 million contingent liability related to the Adversary Proceeding. See *Note 17—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for the nature and status of this litigation and the Company's liability accrual. The Company expects the U.S. Bankruptcy Court for the Southern District of New York (Bankruptcy Court) to issue a judgment that will then be subject to appeal. Following a judgment, there are potential short-term and long-term liquidity impacts to the Company.

In the short term, following a judgment the Company would be required either to pay the damage award or appeal the judgment. In the appellate process, the Company may be required to post a bond or provide sufficient security within 14 days of the judgment to stay execution of the judgment by the plaintiffs pending the outcome of the appellate process. As the Bankruptcy Court has not yet issued a judgment, the Company is unable to estimate the potential amount of any bond or other security, or whether the Company would be required to provide a bond or other security, given the value of the assets owned by Kerr-McGee. Other short-term impacts could include a settlement and payment of any amounts agreed to with the plaintiffs, although a settlement is not considered probable at this time. In the event the Company is required to provide a bond or payment of any damage award or settlement with the plaintiffs in the short term, the Company expects to be able to access the surety bond market and supplement or support such bonding by (i) using a portion of available cash on hand ($3.7 billion at December 31, 2013), (ii) accessing the Company's $5.0 billion Facility, (iii) entering into new financing arrangements, or (iv) identifying and monetizing assets in an orderly manner, including those previously identified and closed through February 2014.

As final resolution through the appellate process could take several years, it is not possible to predict the Company's resources that will be available at that time. As the Company continues to evaluate its liquidity needs, it will consider events that may occur with respect to the Adversary Proceeding. For example, to meet future cash demands, the Company could adjust capital spending or assets could be divested.

Revolving Credit Facility Borrowings under the $5.0 billion Facility bear interest, at the Company's election, at (i) the London Interbank Offered Rate (LIBOR) plus a margin ranging from 1.25% to 2.50%, based on the Company's credit rating, or (ii) the greatest of (a) the JPMorgan Chase Bank, N.A. prime rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) one-month LIBOR plus 1%, plus, in each case, an applicable margin ranging from 0.25% to 1.50%.

Obligations incurred under the $5.0 billion Facility, as well as obligations Anadarko has to lenders or their affiliates pursuant to certain derivative instruments as discussed in *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, are guaranteed by certain of the Company's wholly owned domestic subsidiaries, and are secured by a perfected first-priority security interest in certain exploration and production assets located in the United States and 65% of the capital stock of certain wholly owned foreign subsidiaries.

Financial Covenants The $5.0 billion Facility contains various customary covenants with which Anadarko must comply, including, but not limited to, limitations on incurrence of indebtedness, liens on assets, and asset sales. Anadarko is also required to maintain, at the end of each quarter, (i) a Consolidated Leverage Ratio of no more than 4.5 to 1.0 (relative to Consolidated EBITDAX for the most recent period of four calendar quarters), (ii) a ratio of Current Assets to Current Liabilities of no less than 1.0 to 1.0, and (iii) a Collateral Coverage Ratio of no less than 1.75 to 1.0, in each case, as defined in the $5.0 billion Facility. The Collateral Coverage Ratio is the ratio of an annually redetermined value of pledged assets to outstanding loans under the $5.0 billion Facility. Additionally, to borrow from the $5.0 billion Facility, the Collateral Coverage Ratio must be no less than 1.75 to 1.0 after giving pro forma effect to the requested borrowing. At December 31, 2013, the Company was in compliance with applicable covenants, and there were no restrictions on its ability to utilize the $5.0 billion Facility.

The covenants contained in certain of the Company's credit agreements provide for a maximum Anadarko debt-to-capitalization ratio of 67%. The covenants do not specifically restrict the payment of dividends; however, the impact of dividends paid on the Company's debt-to-capitalization ratio must be considered to ensure covenant compliance. At December 31, 2013, Anadarko was in compliance with all financial covenants.

Zero-Coupon Notes In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing the Zero Coupons. The Zero Coupons mature in October 2036 and have an aggregate principal amount due at maturity of $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, which would cause the Company to repay up to the then-accreted value of the outstanding Zero Coupons. The accreted value of the outstanding Zero Coupons was $727 million at December 31, 2013, and will be $756 million in October 2014 (the next potential put date). The Company considers its cash-flow-generating capacity and access to additional liquidity sufficient to continue to satisfy the Company's debt-service and other obligations, including the potential early repayment of the outstanding Zero Coupons.

WES Funding Sources Anadarko's consolidated subsidiary, WES, uses cash flows from operations to fund ongoing operations (including capital investments in the ordinary course of business), service its debt, and make distributions to its equity holders. As needed, WES supplements cash generated from its operating activities with proceeds from debt or equity issuances or borrowings under its five-year, $800 million senior unsecured revolving credit facility maturing in March 2016 (RCF).

Borrowings under the RCF bear interest at (i) LIBOR plus an applicable margin ranging from 1.30% to 1.90%, or (ii) the greatest of (a) the Wells Fargo Bank, National Association prime rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) one-month LIBOR plus 1%, plus, in each case, an applicable margin ranging from 0.30% to 0.90%. At December 31, 2013, WES was in compliance with all covenants contained in its RCF and had no outstanding borrowings under its RCF. See *Financing Activities* below.

In February 2014, WES entered into a five-year, $1.2 billion senior unsecured revolving credit facility maturing in February 2019 (2014 RCF), which amended and restated the RCF. The 2014 RCF is expandable to a maximum of $1.5 billion. Borrowings under the 2014 RCF bear interest at (i) LIBOR plus an applicable margin ranging from 0.975% to 1.45%, or (ii) the greatest of (a) the Wells Fargo Bank, National Association prime rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) one-month LIBOR plus 1%, plus, in each case, an applicable margin ranging from zero to 0.45%.

During 2013, WES began selling common units under a continuous offering program, which authorized the issuance of up to an aggregate of $125 million of common units. WES completed sales totaling 686 thousand common units during 2013 at an average price per unit of $60.84, generating gross proceeds of $42 million.

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) $300 million per occurrence from Oil Insurance Limited (OIL) for physical damage to Anadarko's properties on a replacement cost basis, blowout/control of well, redrill, and sudden and accidental pollution; (b) $700 million 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) $400 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.

Anadarko's property and casualty insurance policies renew in June of each year. At the next renewal date scheduled for June 2014, the Company may not be able to secure similar coverage for the same costs, if at all. Future insurance coverage costs for the oil and gas industry could increase and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that the Company considers economically acceptable.

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.

Following is a discussion of significant sources and uses of cash flows for the three-year period ended December 31, 2013. Forward-looking information related to the Company's liquidity and capital resources is discussed in *Outlook* that follows.

Sources of Cash

Operating Activities Anadarko's cash flows from operating activities in 2013 was $8.9 billion compared to $8.3 billion in 2012 and $2.5 billion in 2011. Cash flows from operating activities for 2013 increased year over year primarily due to higher sales volumes, higher average natural-gas prices, and the favorable impact of changes in working capital items, partially offset by lower average crude-oil and NGLs prices and a decrease in cash collected in 2013 associated with the Algeria exceptional profits tax receivable. Cash flows from operating activities for 2012 increased year over year primarily due to the $4.0 billion payment to BP related to the Settlement Agreement in 2011, $1.0 billion collected in 2012 associated with the Algeria exceptional profits tax receivable, higher sales volumes, and the favorable impact of changes in working capital items, partially offset by lower average NGLs and natural-gas prices.

One of the primary sources of variability in the Company's cash flows from operating activities is fluctuation in commodity prices, which Anadarko partially mitigates by entering into commodity derivatives. Sales-volume changes also impact cash flow, but have not been as volatile as commodity prices. Anadarko's long-term cash flows from operating activities is dependent on commodity prices, sales volumes, costs required for continued operations, and debt service.

Investing Activities Anadarko received pretax sales proceeds related to property divestiture transactions of $567 million in 2013, $657 million in 2012, and $555 million in 2011.

Financing Activities During 2013, Anadarko's consolidated subsidiary, WES, borrowed $710 million under its RCF, primarily to fund the 2013 acquisitions of an interest in certain gas-gathering systems located in the Marcellus shale in north-central Pennsylvania and an intrastate pipeline in southwestern Wyoming, and for other general partnership purposes, including the funding of capital expenditures. During 2013, WES issued approximately 12 million common units to the public, including the continuous offering program discussed in *WES Funding Sources*. These offerings raised net proceeds of $725 million, which were primarily used to repay outstanding RCF borrowings and for other general partnership purposes, including funding of WES's capital expenditures. Also in 2013, WES completed a public offering of $250 million aggregate principal amount of 2.600% Senior Notes due 2018, with net proceeds from the offering used to repay outstanding borrowings under its RCF.

During 2012, WES borrowed $374 million under its RCF, primarily to fund the acquisition of certain midstream assets from Anadarko. Also during 2012, WES completed a public offering of $670 million aggregate principal amount of 4.000% Senior Notes due 2022 and issued five million common units to the public, raising net proceeds of $212 million. Proceeds from these public offerings were used to repay outstanding RCF borrowings and for other general partnership purposes, including the funding of capital expenditures.

In December 2012, WGP completed its IPO of approximately 20 million common units representing limited partner interests in WGP at a price of $22.00 per common unit, for net proceeds of $411 million. The proceeds were used by WGP to purchase common and general partner units in WES, and were in turn used by WES for general partnership purposes, including the funding of WES capital expenditures.

During 2011, Anadarko borrowed $2.5 billion under the $5.0 billion Facility to fund a portion of the $4.0 billion payment to BP associated with the Settlement Agreement (see *Deepwater Horizon Settlement Costs* below). In 2011, WES borrowed $320 million under its RCF primarily to fund a third-party asset acquisition and $250 million under its RCF to repay the senior unsecured term loan (Term Loan) as discussed in *Uses of Cash*. Also during 2011, WES issued approximately 10 million common units to the public, raising net proceeds of $328 million, which were used to repay outstanding RCF borrowings and for other general partnership purposes. In addition, during 2011, WES completed a public offering of $500 million aggregate principal amount of 5.375% Senior Notes due 2021, with net proceeds from the offering used to repay amounts then outstanding under its RCF.

Uses of Cash

Anadarko invests significant capital to develop, acquire, and explore for oil and natural-gas resources and to expand its midstream infrastructure. The Company also uses cash to fund ongoing operating costs, capital contributions to equity subsidiaries, debt repayments, and distributions to its shareholders.

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

millions	**2013**	2012	2011
Property acquisitions			
Exploration	**$ 327**	$ 239	$ 647
Development	**324**	—	—
Exploration	**1,970**	2,064	1,469
Development	**4,865**	4,064	3,525
Total oil and gas costs incurred (1)	**7,486**	6,367	5,641
Less corporate acquisitions and non-cash property exchanges	**(6)**	(32)	(17)
Less asset retirement costs	**(180)**	(98)	(148)
Less geological and geophysical, exploration overhead, delay rentals expenses, and other expenses	**(430)**	(401)	(450)
Total oil and gas capital expenditures	**6,870**	5,836	5,026
Gathering, processing, and marketing and other (2)	**1,653**	1,475	1,527
Total capital expenditures (1)	**$ 8,523**	$ 7,311	$ 6,553

(1) Oil and gas costs incurred represent costs related to finding and developing oil and gas reserves. Capital expenditures represent additions to property and equipment excluding corporate acquisitions, property exchanges, and asset retirement costs. Capital expenditures and costs incurred are presented on an accrual basis. Additions to properties and equipment and dry hole costs on the Consolidated Statements of Cash Flows include certain adjustments that give effect to the timing of actual cash payments in order to provide a cash-basis presentation.

(2) Includes WES capital expenditures of $792 million in 2013, $529 million in 2012, and $439 million in 2011.

The Company's capital spending increased by 17% for the year ended December 31, 2013, due to development drilling onshore and offshore in the United States and acquisitions of oil and gas development properties and domestic onshore plants and gathering systems. In 2013, Anadarko exchanged certain oil and gas properties in the Wattenberg field with a third party to enhance its core acreage position, in which $106 million of capital was incurred. Also in 2013, Anadarko acquired certain oil and gas properties and related assets in the Moxa area of Wyoming for $310 million, including $306 million reflected in the table above representing the fair value of the oil and gas properties acquired. In 2013, the Company acquired a 33.75% interest in gas-gathering systems located in the Marcellus shale in north-central Pennsylvania for $135 million and an intrastate pipeline in southwestern Wyoming for $28 million. These increases were offset by lower capital spending associated with decreased exploration drilling in West Africa and U.S. onshore and lower capital requirements to Anadarko related to development projects as a result of the carried-interest arrangements discussed below.

In 2013, the Company entered into a carried-interest arrangement that requires a third-party partner to fund $860 million of Anadarko's capital costs in exchange for a 12.75% working interest in the Heidelberg development, located in the Gulf of Mexico. The third-party funding is expected to cover the substantial majority of Anadarko's expected future capital costs through first production, which is expected to occur by mid-2016. At December 31, 2013, $119 million of the total $860 million obligation had been funded.

In 2012, the Company entered into a carried-interest arrangement that requires a third-party partner to fund $556 million of Anadarko's capital costs in exchange for a 7.2% working interest in the Lucius development, located in the Gulf of Mexico. The carry obligation is expected to cover the substantial majority of the Company's expected future capital costs through first production, which is expected to occur in the second-half of 2014. At December 31, 2013, $416 million of the $556 million obligation had been funded.

The Company's capital spending increased 12% for the year ended December 31, 2012, primarily due to increased exploration drilling onshore and offshore in the United States, and in East and West Africa; increased development drilling onshore in the United States; construction costs related to the development of the Lucius project located in the Gulf of Mexico; and higher expenditures for additional capital projects at domestic onshore plants and gathering systems. These increases were partially offset by lower exploration property acquisition costs, primarily onshore in the United States, and 2011 midstream asset acquisitions. In 2011, Anadarko increased its ownership interest in the Wattenberg Plant to 100% by acquiring an additional 93% interest for $576 million. Also in 2011, the Company acquired a third-party natural-gas processing plant and related gathering systems, located in the Rocky Mountains area, for $302 million.

Deepwater Horizon Settlement Costs In October 2011, the Company and BP entered into the Settlement Agreement. The Company paid $4.0 billion and transferred its interest in the Macondo well and Lease to BP. Refer to *Note 17—Contingencies—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Pension Contributions During 2013, the Company made contributions of $123 million to its funded pension plans, $37 million to its unfunded pension plans, and $14 million to its unfunded other postretirement benefit plans. The increase in contributions to the funded pension plans in 2013 resulted from a decrease in the discount rates used for funding purposes. The Company expects to contribute $103 million to its funded pension plans, $19 million to its unfunded pension plans, and $15 million to its unfunded other postretirement benefit plans in 2014.

During 2012, the Company made contributions of $101 million to its funded pension plans, $6 million to its unfunded pension plans, and $19 million to its unfunded other postretirement benefit plans. The decrease in contributions to the funded pension plans in 2012 resulted from an increase in the discount rates used for funding purposes.

Investments During 2013, the Company made capital contributions of $396 million to equity subsidiaries, which are included in Other—net under Investing Activities in the Consolidated Statement of Cash Flows. These contributions were primarily associated with joint ventures to build the Front Range Pipeline, the Texas Express Pipeline, and two fractionation trains in Mont Belvieu. The Company made capital contributions to equity subsidiaries of $205 million in 2012 and $47 million in 2011.

Debt Retirements and Repayments During 2013, WES repaid $710 million of borrowings under its RCF with proceeds from debt and equity offerings, as discussed in *Sources of Cash.*

During 2012, the Company repaid the entire $2.5 billion of borrowings under its $5.0 billion Facility, and retired $131 million of 6.125% Senior Notes that matured in March 2012 and $39 million of 5.000% Senior Notes that matured in October 2012. In addition, WES repaid $374 million of borrowings under its RCF.

During 2011, WES repaid $619 million of borrowings under its RCF and a $250 million Term Loan primarily from proceeds from public debt and equity offerings, as discussed in *Sources of Cash*. In addition, the Company repaid $285 million principal amount of 6.875% Senior Notes that matured in September 2011.

For additional information on the Company's debt instruments, 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.

Common Stock Dividends and Distributions to Noncontrolling Interest Owners Anadarko paid dividends to its common stockholders of $274 million in 2013, $181 million in 2012, and $181 million in 2011. During the third quarter of 2013, Anadarko increased the quarterly dividend paid to its common stockholders from $0.09 per share to $0.18 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 will be determined by the Board of Directors on a quarterly basis and will depend on earnings, financial conditions, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors.

WES distributed to its unitholders, other than Anadarko, an aggregate of $130 million in 2013, $100 million in 2012, and $72 million in 2011. 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 $0.60 per common unit for the fourth quarter of 2013 (to be paid in February 2014).

WGP distributed to its unitholders, other than Anadarko, an aggregate of $12 million during 2013. WGP declared a cash distribution of $0.23125 per unit for the fourth quarter of 2013 (to be paid in February 2014).

Other During 2011, the Company and its partners in the Jubilee project in Ghana purchased the FPSO. The Company's cash contribution was $108 million.

Outlook

There is uncertainty related to the ultimate outcome of the Adversary Proceeding. See *Effects of Tronox Adversary Proceeding on Liquidity* for more information.

The Company is committed to the execution of its worldwide exploration, appraisal, and development programs. The Company plans to allocate approximately 70% of its 2014 capital spending to development activities, 15% to exploration activities, and 15% to gas-gathering and processing activities and other business activities. The Company expects its 2014 capital spending by area to be approximately 60% for the U.S. onshore region and Alaska, 15% for the Gulf of Mexico, 15% for Midstream and other, and 10% for International.

Anadarko believes that its cash on hand and expected level of operating cash flows will be sufficient to fund the Company's projected operational and capital programs for 2014 and continue to meet its other current obligations. The Company's cash on hand is available for use and could be supplemented, as needed, with available borrowing capacity under the $5.0 billion Facility. The Company may also enter into carried-interest arrangements with third parties to fund certain capital expenditures and execute asset divestitures to supplement cash flow.

The Company continuously monitors its liquidity needs, coordinates its capital expenditure program with its expected cash flows and projected debt-repayment schedule, and evaluates available funding alternatives in light of current and expected conditions. To reduce commodity-price risk and increase the predictability of 2014 cash flows, Anadarko entered into strategic derivative positions, which cover a portion of its anticipated natural-gas and crude-oil sales volumes for 2014. For details of derivative positions at December 31, 2013, see *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

The Company sold a 10% working interest in Rovuma Offshore Area 1 in Mozambique for $2.64 billion in February 2014. Anadarko remains the operator of Rovuma Offshore Area 1 with a working interest of 26.5%.

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 natural gas, crude oil, and NGLs, as well as for other oil and gas activities as discussed below in *Obligations and Commitments*. 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 and Commitments

The following is a summary of the Company's obligations at December 31, 2013:

	Obligations by Period (1)				
millions	2014	2015-2016	2017-2018	2019 and beyond	Total
Total debt					
Principal—current borrowings	$ 500	$ —	$ —	$ —	$ 500
Principal—long-term borrowings (2)(3)	275	1,750	2,364	10,313	14,702
Principal—capital lease obligation	—	—	—	8	8
Investee entities' debt (4)	—	—	—	2,853	2,853
Interest on borrowings	823	1,577	1,228	7,064	10,692
Interest on capital lease obligations	1	1	1	7	10
Investee entities' interest (4)	37	115	229	3,728	4,109
Operating leases					
Drilling rig commitments	880	1,574	750	98	3,302
Production platforms	36	54	43	73	206
Other	48	75	41	18	182
Asset retirement obligations	409	277	342	994	2,022
Midstream and marketing activities	825	1,780	1,644	3,071	7,320
Oil and gas activities	1,445	1,413	693	639	4,190
Derivative liabilities (5)	522	186	—	—	708
Uncertain tax positions, interest, and penalties (6)	17	3	135	—	155
Environmental liabilities	18	68	5	35	126
Total	$ 5,836	$ 8,873	$ 7,475	$ 28,901	$ 51,085

(1) This table does not include the Tronox-related contingent liability, other litigation-related contingent liabilities, or the Company's pension and postretirement benefit obligations. See *Note 17—Contingencies—Tronox Litigation* and *Note 22—Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(2) The Company's $275 million aggregate principal amount of 5.750% Senior Notes due June 2014 is classified as long-term debt on the Company's Consolidated Balance Sheet, as the Company has the ability and intent to refinance this obligation using long-term debt. See *Note 12—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(3) Includes the fully accreted principal amount of the Zero Coupons of $2.4 billion as coming due after 2018. While the Zero Coupons do not mature until 2036, the outstanding Zero Coupons can be put to the Company each October at up to the then-accreted value. The Company could be required to repurchase the outstanding Zero Coupons at $756 million in October 2014 (the next potential put date).

(4) 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 investments and the obligations are presented net on the Consolidated Balance Sheets in other long-term liabilities—other for all periods presented. These notes payable provide for a variable rate of interest, reset quarterly. Therefore, future interest payments presented in the table above are estimated using the forward LIBOR rate curve. Further, the above table does not reflect the preferred return that Anadarko receives on its investment in these entities, which is also LIBOR-based, with a lower margin than the margin on the associated notes payable. See *Note 10—Equity-Method Investments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(5) Represents Anadarko's gross derivative liability after taking into account the impacts of netting margin and collateral balances deposited with counterparties. See *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(6) See *Note 19—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Operating Leases Operating lease obligations include approximately $3.1 billion related to eight offshore drilling vessels and $155 million related to certain contracts for U.S. onshore drilling rigs. Anadarko manages its access to rigs to execute its drilling strategy over the next several years. 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. At December 31, 2013, the Company had $388 million in various commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, and aircraft. For additional information, see *Note 16—Commitments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Asset Retirement Obligations Anadarko is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The majority of Anadarko's asset retirement obligations (AROs) relate to the plugging of wells and the related abandonment of oil and gas properties. The Company's AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. 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.

Midstream and Marketing Activities Anadarko has entered into various processing, transportation, storage, and purchase agreements to access markets and provide flexibility to sell its natural gas, crude oil, and NGLs in certain areas.

Oil and Gas Activities At December 31, 2013, Anadarko had various long-term contractual commitments pertaining to exploration, development, and production activities that extend beyond 2013. The Company has work-related commitments for, among other things, drilling wells, obtaining and processing seismic, and fulfilling rig commitments. The preceding table includes long-term drilling and work-related commitments of $4.2 billion, comprised of approximately $3.1 billion related to the United States and $1.1 billion related to international locations.

Environmental Liabilities Anadarko is subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. At December 31, 2013, the Company's Consolidated Balance Sheet included a $126 million liability for remediation and reclamation obligations. The Company continually monitors the liability recorded and ongoing remediation and reclamation activities, and believes the amount recorded is appropriate. For additional information on environmental issues, see *Risk Factors* under Item 1A of this Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP in the United States 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; asset retirement obligations; 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. Management considers the following to be its most critical accounting estimates that involve judgment. The selection and development of these estimates is discussed with the Company's Audit Committee.

Oil and Gas Activities

Anadarko applies the successful efforts method of accounting to account for its oil and gas activities. Under this method, acquisition costs and the costs associated with drilling exploratory wells are capitalized pending the determination of proved oil and gas reserves. Exploration geological and geophysical costs and other costs of carrying properties such as delay rentals are expensed as incurred.

Acquisition Costs

Acquisition costs of unproved 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.

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. Significant undeveloped leasehold costs are assessed for impairment at a lease level or resource play (for example, the Greater Natural Buttes area in the Rockies), while leasehold acquisition costs associated with prospective areas that have limited or no previous exploratory drilling are generally assessed for impairment by major prospect area. 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 oil and gas 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 Consolidated Statement of Income.

Certain of the Company's unproved property costs are associated with acquired properties to which proved developed producing reserves are also attributed. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by the Company's continuing exploration and development programs.

Another portion of the Company's unproved property costs is associated with the Land Grant acreage, where the Company owns mineral interests in perpetuity and plans to continue to explore and evaluate the acreage.

A change in the Company's expected future plans or the operating environment for exploration and development could cause an impairment of the Company's unproved property.

Exploratory Costs

Under the successful efforts method of accounting, exploratory costs associated with a well discovering hydrocarbons are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. 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. 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.

Proved Reserves

Anadarko estimates its proved oil and gas reserves as defined by the SEC and the FASB. This definition includes crude 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.

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. Revisions are necessary due to changes in, among other things, 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 impairments.

Fair Value

The Company estimates fair value for derivatives, 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, guarantees, pension plan assets, initial measurements of AROs, and financial instruments that require fair-value disclosure, including cash and cash equivalents, accounts receivable, accounts payable, and debt. 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, income, or market valuation 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 projected cash flows, and discounts the expected cash flows using a commensurate risk-adjusted discount rate. The market approach is based on management's best assumptions regarding prices and other relevant information from market transactions involving comparable assets. 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, future net cash flows, 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.

Business Combinations

Accounting for the acquisition of a business requires the assets and liabilities of the acquired business to be recorded at fair value. Deferred taxes are recorded for any differences between the fair value and the tax basis of acquired assets and liabilities. Any excess of the purchase price over the amounts assigned to the identifiable assets and liabilities is recorded as goodwill.

Goodwill

At December 31, 2013, the Company had $5.5 billion of goodwill. The Company tests goodwill for impairment annually at October 1, or more frequently as circumstances dictate. The first step in assessing whether an impairment of goodwill is necessary is an optional qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is greater than its carrying amount. If the Company concludes that fair value of the reporting unit more than likely exceeds the related carrying amount, then goodwill is not impaired and further testing is not necessary. If the qualitative assessment is not performed or 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.

Because quoted market prices for the Company's reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing goodwill impairment tests, when such tests are necessary. Management uses all available information 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 observable for the oil and gas exploration and production reporting unit, 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 oil and gas exploration and production reporting unit, the Company assumes production profiles used in its estimation of reserves that are disclosed in the Company's supplemental oil and gas disclosures, market prices based on the forward price curve for oil and gas at the test date (adjusted for location and quality differentials), capital and operating costs consistent with pricing and expected inflation rates, and discount rates that management believes a market participant would use based upon the risks inherent in Anadarko's operations.

For the Company's other gathering and processing, WES gathering and processing, and transportation reporting units, the Company estimates fair value by applying an estimated multiple to projected EBITDA. The Company considered 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 sustained price declines, cost increases, regulatory or political environment changes, and other changes in market conditions such as decreased prices in market-based transactions for similar assets, as well as difficulty or potential delays in obtaining drilling permits or other unanticipated events.

Environmental Obligations and Other Contingencies

Management makes judgments and estimates when it establishes liabilities for environmental remediation, litigation, and other contingent matters. Losses for such matters are charged to expense when it is probable that a liability has been incurred and a reasonable estimate of the liability can be made. If a range of loss can be estimated, but no amount within the range is a better estimate than any other, the minimum amount of the range is accrued.

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 in the process 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.

Estimates of environmental liabilities are based on a variety of matters, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change the Company's estimate of environmental-remediation costs, such as changes in laws and regulations, changes in the interpretation or administration of laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contaminated soil and groundwater, and changes in costs of labor, equipment, and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures that could arise related to environmental or other contingent matters and actual costs may vary significantly from the Company's estimates. The Company's in-house legal counsel and environmental 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.

Impairment of Long-Lived Assets

A long-lived asset other than unproved oil and gas property is evaluated for potential impairment whenever events or changes in circumstances indicate that its carrying value may be greater than its future net undiscounted cash flows. Impairment, if any, is measured as the excess of an asset's carrying amount over its estimated fair value. The Company uses a variety of fair-value measurement techniques when market information for the same or similar assets does not exist.

Derivative Instruments

All derivative instruments, other than those that satisfy specific exceptions, are recorded at fair value. If market quotes are not available to estimate fair value, management's best estimate of fair value is based on the quoted market price of derivatives with similar characteristics or determined through industry-standard valuation techniques.

The Company's derivative instruments are either exchange-traded or transacted in an over-the-counter market. Valuation is determined by reference to readily available public data for similar instruments. Option fair values are measured using the Black-Scholes option-pricing model and verified by comparing a sample to market quotes for similar options. Gains and losses on derivative instruments are recognized currently in earnings.

Income Taxes

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 Company routinely assesses the realizability of its deferred tax assets and reduces such assets 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 potential uncertain tax positions and, if required, establishes accruals for such amounts. 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. 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.

Benefit Plan Obligations

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. Determination of the benefit obligations for the Company's defined-benefit pension plans and postretirement benefit plans impacts the recorded amounts for such obligations on the balance sheet and the amount of benefit expense recorded to the income statement.

Accounting for pension and other postretirement benefit obligations involves many assumptions, the most significant of which are the discount rate used to measure the present value of plan benefit obligations, the expected long-term rate of return on plan assets (for funded pension plans), the rate of future increases in compensation levels of participating employees, and the future level of health care costs (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.

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.

Discount rate

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.

Expected long-term rate of return

The expected long-term rate of return on plan assets assumption was determined using the year-end 2013 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, and inflation. Returns on fixed-income securities are generally based on expected inflation, real bond yield, and risk spread (as appropriate), adjusted for the expected effect that changing yields have on the rate of return. Other asset class returns are derived from their relationship to the equity and fixed income markets. Because the assumption reflects the Company's expectation of average annualized return over a long time horizon, generally, it is not expected to be significantly revised from year to year, even though actual rates of investment return from year to year often exhibit significant volatility.

Rate of compensation increases

The Company's rate of compensation increases assumption is based on its long-term plans for compensation increases specific to covered employee groups and expected economic conditions. The assumed rate of salary increases includes the effects of merit increases, promotions, and general labor cost inflation within the oil and gas industry.

Health care cost trend rate

The health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends.

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. In addition, foreign-currency exchange-rate risk exists due to anticipated foreign-currency denominated payments and receipts. These risks can affect revenues and cash flows from operating, investing, and financing activities. The Company's risk-management policies provide for the use of derivative instruments to manage these risks. The types of commodity derivative instruments utilized 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 commodity 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 11—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 natural gas, crude oil, and NGLs. Management expects energy prices to remain volatile and unpredictable. 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 and sustained 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 816 Bcf of natural gas and 39 MMBbls of crude oil at December 31, 2013, with a net derivative asset position of $23 million. Based on actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $618 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $609 million. However, any cash received or paid to settle these derivatives would be substantially offset by the realized sales value of equivalent production.

Derivative Instruments Held for Trading Purposes At December 31, 2013, the Company had a net derivative asset position of $25 million (gains of $39 million and losses of $14 million) on outstanding derivative instruments entered into for trading purposes. Based on actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would not materially impact the Company's gains or losses on these derivative instruments.

For additional information regarding the Company's marketing and trading portfolio, see *Marketing Activities* under Items 1 and 2 of this Form 10-K.

INTEREST-RATE RISK Any borrowings under the $5.0 billion Facility and the WES RCF are subject to variable interest rates. The balance of Anadarko's long-term debt on the Company's Consolidated Balance Sheets is subject to fixed interest rates. The Company's $2.9 billion of LIBOR-based obligations, which are presented on the Company's Consolidated Balance Sheets net of preferred investments in two non-controlled entities, give rise to minimal net interest-rate risk because coupons on the related preferred investments are also LIBOR-based. A 10% increase in LIBOR would not impact the Company's interest cost on fixed-rate debt already outstanding, but would affect the fair value of outstanding fixed-rate debt.

At December 31, 2013, the Company had a net derivative liability position of $654 million related to interest-rate swaps. A 10% increase (decrease) in the three-month LIBOR interest-rate curve would increase (decrease) the aggregate fair value of outstanding interest-rate swap agreements by approximately $146 million. However, any change in the interest-rate derivative gain or loss could be substantially offset by actual borrowing costs associated with any future debt issuances or borrowings under its $5.0 billion Facility. For a summary of the Company's outstanding interest-rate derivative positions, see *Note 11—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

FOREIGN-CURRENCY EXCHANGE-RATE RISK Anadarko's operating revenues are realized in U.S. dollars, and the predominant portion of Anadarko's capital and operating expenditures are U.S.-dollar-denominated. Exposure to foreign-currency risk generally arises in connection with project-specific contractual arrangements and other commitments. Near-term foreign-currency-denominated expenditures are primarily in euros, Brazilian reais, British pounds sterling, Mozambican meticais, and Colombian pesos. Management periodically enters into various risk-management transactions to mitigate a portion of its exposure to foreign-currency exchange-rate risk.

The Company has risk related to exchange-rate changes applicable to cash held in escrow pending final determination of the Company's Brazilian tax liability for its 2008 divestiture of the Peregrino field offshore Brazil. The Brazilian tax matter is currently under consideration by the Brazilian courts. See *Note 17—Contingencies—Other Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. At December 31, 2013, cash of $144 million was held in escrow. A 10% increase or decrease in the foreign-currency exchange rate would not materially impact the Company's gain or loss related to foreign currency.

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 position, 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 to the Company's Management and Directors regarding the preparation and fair presentation of published 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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013. This assessment was based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we believe that as of December 31, 2013, the Company's internal control over financial reporting was effective based on those criteria.

KPMG LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2013.

/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 28, 2014

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Anadarko Petroleum Corporation'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 *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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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 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.

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.

In our opinion, Anadarko Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2013 and 2012, and 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, 2013, and our report dated February 28, 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 28, 2014

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2013 and 2012, and 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, 2013. 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 conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three–year period ended December 31, 2013, 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), Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2014 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 28, 2014

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
millions except per-share amounts	**2013**	2012	2011
Revenues and Other			
Natural-gas sales	**$ 3,388**	$ 2,444	$ 3,300
Oil and condensate sales	**9,178**	8,728	8,072
Natural-gas liquids sales	**1,262**	1,224	1,462
Gathering, processing, and marketing sales	**1,039**	911	1,048
Gains (losses) on divestitures and other, net	**(286)**	104	85
Total	**14,581**	13,411	13,967
Costs and Expenses			
Oil and gas operating	**1,092**	976	993
Oil and gas transportation and other	**1,022**	955	891
Exploration	**1,329**	1,946	1,076
Gathering, processing, and marketing	**869**	763	791
General and administrative	**1,090**	1,246	1,060
Depreciation, depletion, and amortization	**3,927**	3,964	3,830
Other taxes	**1,077**	1,224	1,492
Impairments	**794**	389	1,774
Algeria exceptional profits tax settlement	**33**	(1,797)	—
Deepwater Horizon settlement and related costs	**15**	18	3,930
Total	**11,248**	9,684	15,837
Operating Income (Loss)	**3,333**	3,727	(1,870)
Other (Income) Expense			
Interest expense	**686**	742	839
(Gains) losses on derivatives, net	**(398)**	(326)	461
Other (income) expense, net	**89**	(4)	4
Tronox-related contingent loss	**850**	(250)	250
Total	**1,227**	162	1,554
Income (Loss) Before Income Taxes	**2,106**	3,565	(3,424)
Income tax expense (benefit)	**1,165**	1,120	(856)
Net Income (Loss)	**941**	2,445	(2,568)
Net income attributable to noncontrolling interests	**140**	54	81
Net Income (Loss) Attributable to Common Stockholders	**$ 801**	$ 2,391	$ (2,649)
Per Common Share			
Net income (loss) attributable to common stockholders—basic	**$ 1.58**	$ 4.76	$ (5.32)
Net income (loss) attributable to common stockholders—diluted	**$ 1.58**	$ 4.74	$ (5.32)
Average Number of Common Shares Outstanding—Basic	**502**	500	498
Average Number of Common Shares Outstanding—Diluted	**505**	502	498
Dividends (per Common Share)	**$ 0.54**	$ 0.36	$ 0.36

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
millions	**2013**	2012	2011
Net Income (Loss)	**$ 941**	$ 2,445	$ (2,568)
Other Comprehensive Income (Loss), net of taxes			
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net [(1)]	**7**	8	10
Adjustments for pension and other postretirement plans			
Net gain (loss) incurred during period [(2)]	**264**	(99)	(136)
Prior service credit (cost) incurred during period [(3)]	**—**	—	7
Amortization of net actuarial (gain) loss to general and administrative expense [(4)]	**83**	61	54
Amortization of net prior service (credit) cost to general and administrative expense	**1**	2	2
Total adjustments for pension and other postretirement plans	**348**	(36)	(73)
Total	**355**	(28)	(63)
Comprehensive Income (Loss)	**1,296**	2,417	(2,631)
Comprehensive income attributable to noncontrolling interests	**140**	54	81
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ 1,156**	$ 2,363	$ (2,712)

(1) Net of income tax benefit (expense) of $(4) million in 2013, $(4) million in 2012, and $(5) million in 2011.
(2) Net of income tax benefit (expense) of $(152) million in 2013, $56 million in 2012, and $77 million in 2011.
(3) Net of income tax benefit (expense) of $(5) million in 2011.
(4) Net of income tax benefit (expense) of $(49) million in 2013, $(32) million in 2012, and $(31) million in 2011.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

millions	December 31, 2013	2012
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 3,698**	$ 2,471
Accounts receivable (net of allowance of $5 million and $7 million)		
Customers	**1,481**	1,473
Others	**1,241**	1,274
Algeria exceptional profits tax settlement	**—**	730
Other current assets	**688**	847
Total	**7,108**	6,795
Properties and Equipment		
Cost	**71,244**	63,598
Less accumulated depreciation, depletion, and amortization	**30,315**	25,200
Net properties and equipment	**40,929**	38,398
Other Assets	**2,082**	1,716
Goodwill and Other Intangible Assets	**5,662**	5,680
Total Assets	**$ 55,781**	$ 52,589
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	**$ 3,530**	$ 2,989
Current asset retirement obligations	**409**	298
Accrued expenses	**1,264**	707
Current portion of long-term debt	**500**	—
Total	**5,703**	3,994
Long-term Debt	**13,065**	13,269
Other Long-term Liabilities		
Deferred income taxes	**9,245**	8,759
Asset retirement obligations	**1,613**	1,587
Tronox-related contingent liability	**850**	—
Other	**1,655**	3,098
Total	**13,363**	13,444
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 522.5 million and 518.6 million shares issued)	**52**	51
Paid-in capital	**8,629**	8,230
Retained earnings	**14,356**	13,829
Treasury stock (18.8 million and 18.1 million shares)	**(895)**	(841)
Accumulated other comprehensive income (loss)	**(285)**	(640)
Total Stockholders' Equity	**21,857**	20,629
Noncontrolling interests	**1,793**	1,253
Total Equity	**23,650**	21,882
Total Liabilities and Equity	**$ 55,781**	$ 52,589

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, 2010	$ 51	$ 7,496	$ 14,449	$ (763)	$ (549)	$ 755	$ 21,439
Net income (loss)	—	—	(2,649)	—	—	81	(2,568)
Common stock issued	—	161	—	—	—	—	161
Dividends—common stock	—	—	(181)	—	—	—	(181)
Repurchase of common stock	—	—	—	(41)	—	—	(41)
Subsidiary equity transactions	—	32	—	—	—	269	301
Conversion of subordinated limited partner units to common units [(1)]	—	162	—	—	—	(162)	—
Distributions to noncontrolling interest owners	—	—	—	—	—	(82)	(82)
Contributions from noncontrolling interest owners	—	—	—	—	—	17	17
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	10	—	10
Adjustments for pension and other postretirement plans	—	—	—	—	(73)	—	(73)
Balance at December 31, 2011	51	7,851	11,619	(804)	(612)	878	18,983
Net income (loss)	—	—	2,391	—	—	54	2,445
Common stock issued	—	249	—	—	—	—	249
Dividends—common stock	—	—	(181)	—	—	—	(181)
Repurchase of common stock	—	—	—	(37)	—	—	(37)
Subsidiary equity transactions	—	130	—	—	—	417	547
Distributions to noncontrolling interest owners	—	—	—	—	—	(112)	(112)
Contributions from noncontrolling interest owners	—	—	—	—	—	16	16
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	8	—	8
Adjustments for pension and other postretirement plans	—	—	—	—	(36)	—	(36)
Balance at December 31, 2012	**51**	**8,230**	**13,829**	**(841)**	**(640)**	**1,253**	**21,882**
Net income (loss)	—	—	**801**	—	—	**140**	**941**
Common stock issued	**1**	**292**	—	—	—	—	**293**
Dividends—common stock	—	—	**(274)**	—	—	—	**(274)**
Repurchase of common stock	—	—	—	**(54)**	—	—	**(54)**
Subsidiary equity transactions	—	**107**	—	—	—	**554**	**661**
Distributions to noncontrolling interest owners	—	—	—	—	—	**(156)**	**(156)**
Contributions from noncontrolling interest owners	—	—	—	—	—	**2**	**2**
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	**7**	—	**7**
Adjustments for pension and other postretirement plans	—	—	—	—	**348**	—	**348**
Balance at December 31, 2013	**$ 52**	**$ 8,629**	**$ 14,356**	**$ (895)**	**$ (285)**	**$ 1,793**	**$ 23,650**

(1) Includes $92 million of tax associated with subsidiary equity transactions that occurred prior to the conversion of subordinated limited partner units to common units.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
millions	**2013**	2012	2011
Cash Flows from Operating Activities			
Net income (loss)	**$ 941**	$ 2,445	$ (2,568)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, and amortization	**3,927**	3,964	3,830
Deferred income taxes	**90**	164	(1,461)
Dry hole expense and impairments of unproved properties	**864**	1,544	625
Impairments	**794**	389	1,774
(Gains) losses on divestitures, net	**470**	71	(22)
Total (gains) losses on derivatives, net	**(392)**	(308)	469
Net cash received in settlement of derivative instruments	**85**	685	147
Other	**246**	232	204
Changes in assets and liabilities			
Deepwater Horizon settlement and related costs	**(2)**	24	(18)
Algeria exceptional profits tax settlement	**730**	(791)	—
Tronox-related contingent loss	**850**	(250)	250
(Increase) decrease in accounts receivable	**(11)**	520	(993)
Increase (decrease) in accounts payable and accrued expenses	**150**	(476)	284
Other items—net	**146**	126	(16)
Net cash provided by (used in) operating activities	**8,888**	8,339	2,505
Cash Flows from Investing Activities			
Additions to properties and equipment and dry hole costs	**(7,721)**	(7,242)	(5,650)
Acquisition of businesses	**(473)**	—	(802)
Divestitures of properties and equipment and other assets	**567**	657	555
Other—net	**(589)**	(284)	(78)
Net cash provided by (used in) investing activities	**(8,216)**	(6,869)	(5,975)
Cash Flows from Financing Activities			
Borrowings, net of issuance costs	**958**	1,042	3,551
Repayments of debt	**(710)**	(3,044)	(1,154)
Repayment of capital lease obligation	**—**	—	(108)
Increase (decrease) in outstanding checks	**(13)**	(69)	149
Dividends paid	**(274)**	(181)	(181)
Repurchase of common stock	**(54)**	(37)	(41)
Issuance of common stock, including tax benefit on share-based compensation awards	**146**	103	30
Sale of subsidiary units	**724**	623	328
Distributions to noncontrolling interest owners	**(156)**	(112)	(82)
Contributions from noncontrolling interest owners	**2**	16	17
Other financing activities	**—**	—	1
Net cash provided by (used in) financing activities	**623**	(1,659)	2,510
Effect of Exchange Rate Changes on Cash	**(68)**	(37)	(23)
Net Increase (Decrease) in Cash and Cash Equivalents	**1,227**	(226)	(983)
Cash and Cash Equivalents at Beginning of Period	**2,471**	2,697	3,680
Cash and Cash Equivalents at End of Period	**$ 3,698**	$ 2,471	$ 2,697

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and marketing of natural gas, crude oil, condensate, natural gas liquids (NGLs), and anticipated production of liquefied natural gas (LNG). In addition, the Company engages in the gathering, processing, treating, and transporting of natural gas, crude oil, and NGLs. The Company also participates in hard-minerals royalty arrangements. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

Basis of Presentation The Consolidated Financial Statements have been prepared in conformity with accounting principles generally accepted in the United States. The Consolidated Financial Statements include the accounts of Anadarko and entities in which it holds a controlling interest. 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 non-controlled entities, over which Anadarko has the ability to exercise significant influence over operating and financial policies, 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 reported as a component of other assets. Certain prior-period amounts have been reclassified to conform to the current-year presentation.

Use of Estimates The preparation of financial statements in accordance with accounting principles generally accepted in the United States 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; asset retirement obligations; 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.

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 quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

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. In addition to market information, the Company incorporates transaction-specific details that, in management's judgment, market participants would take into account in measuring fair value.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

1. Summary of Significant Accounting Policies (Continued)

In arriving at fair-value estimates, the Company uses the most 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 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, asset retirement obligations, exit or disposal costs, and capital lease assets where the present value of lease payments is greater than the fair value of the leased asset.

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

The Company recognizes sales revenues for natural gas, oil and condensate, 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 the services are performed or product is sold. These revenues are included in gathering, processing, and marketing sales in the Consolidated Statements of Income.

Marketing margins related to the Company's production are included in natural-gas sales, oil and condensate sales, and NGLs sales. Marketing margins related to sales of commodities purchased from third parties and gains and losses on derivatives related to such marketing activities are included in gathering, processing, and marketing sales in the Consolidated Statements of Income.

The Company enters into buy/sell arrangements related to the transportation of a portion of its crude-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 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.

1. Summary of Significant Accounting Policies (Continued)

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.

Properties and Equipment Properties and equipment are stated at cost less accumulated depreciation, depletion, and amortization expense (DD&A). Costs of improvements that appreciably improve the efficiency or productive capacity of existing properties or extend their lives 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.

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. If an exploratory well provides evidence to justify potential completion as a producing well, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination 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. At the end of each quarter, management reviews the status of all suspended exploratory well 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, 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 oil and gas 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 term 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 oil and gas 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 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, 2013, 2012, AND 2011

1. Summary of Significant Accounting Policies (Continued)

Asset Retirement Obligations 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. If estimated future costs of AROs change, an adjustment is recorded to both the asset retirement obligation 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 7—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 unit-of-production (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 47 years for gathering facilities.

Goodwill and Other Intangible Assets Goodwill is subject to annual impairment testing at October 1 (or more frequent testing as circumstances dictate). Anadarko has allocated goodwill to the following reporting units: oil and gas exploration and production, other gathering and processing, Western Gas Partners, LP (WES) gathering and processing, and transportation. Changes in goodwill may result from, among other things, impairments, future acquisitions, or future divestitures. See *Note 8—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. Other intangible assets are amortized over their estimated useful lives and are assessed for impairment whenever impairment indicators are present. See *Note 8—Goodwill and Other Intangible Assets.*

Derivative Instruments Anadarko uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risk. Derivatives are carried on the balance sheet at fair value and are included in other current assets, other assets, accrued expenses, 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 and will be reclassified to earnings in future periods as the economic transactions to which the derivatives relate affect earnings. See *Note 11—Derivative Instruments*.

1. Summary of Significant Accounting Policies (Continued)

Accounts Payable Accounts payable included liabilities of $326 million at December 31, 2013, and $339 million at December 31, 2012, 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 reflected in cash flows from financing activities.

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*.

Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans The Company measures pension plan assets at fair value. 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 the health care cost trend rate (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.

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. See *Note 22—Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans*.

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 9—Noncontrolling Interests*.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

1. Summary of Significant Accounting Policies (Continued)

Income Taxes The Company files various U.S. federal, state, and foreign income tax returns. 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). See *Note 19—Income Taxes*.

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 total shareholder return (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 or discounted-cash-flow methodology.

The Company records compensation cost, net of estimated forfeitures, for share-based compensation awards over the requisite service period using the straight-line method. An adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the awards. 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 is adjusted for fair-value changes so that the expense recognized for each award is equivalent to the amount to be paid. See *Note 15—Share-Based Compensation*.

Earnings Per Share The Company's basic earnings per share (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 as appropriate. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, and performance-based stock awards, if the inclusion of these items is dilutive. See *Note 13—Stockholders' Equity*.

2. Acquisitions, Divestitures, and Assets Held for Sale

Acquisitions The following summarizes acquisitions made during 2013 and 2011. There were no acquisitions made during 2012.

millions, except percentages	Percentage Acquired	Cash Paid	
2013			
Certain oil and gas properties and related assets in the Moxa area of Wyoming	100%	$ 310	(1)
Gas-gathering systems in the Marcellus shale in north-central Pennsylvania	33.75%	135	
Joint venture formed to design, construct, and own two fractionators located in Mont Belvieu, Texas	25%	78	
Intrastate pipeline in southwestern Wyoming	100%	28	
2011			
Natural-gas processing plant and related gathering systems in northeast Colorado	100%	302	
Natural-gas processing plant (Wattenberg Plant) in northeast Colorado	93%	500	(2)

(1) Includes $306 million that represents the fair value of the oil and gas properties acquired.

(2) The Company recognized a $76 million loss on preexisting contracts with the previous Wattenberg Plant owner in addition to the cash paid in the Wattenberg Plant acquisition. Anadarko operates and owns a 100% interest in the Wattenberg Plant.

Divestitures In 2013, sale proceeds of $509 million were primarily related to the Company's divestiture of its interests in a soda ash joint venture and certain U.S. onshore and Indonesian oil and gas properties. Net gains of $234 million were primarily related to the Company's divestiture of its interests in the soda ash joint venture and certain U.S. oil and gas properties.

In 2012, sale proceeds of $433 million were primarily related to U.S. oil and gas properties and net losses of $43 million were primarily related to Indonesian oil and gas properties. In 2011, the Company received $419 million related to contingent consideration received for the 2008 divestiture of its interest in the Peregrino field offshore Brazil.

In February 2014, the Company sold a 10% working interest in Rovuma Offshore Area 1 in Mozambique for $2.64 billion. Also in February 2014, the Company entered into an agreement to sell its oil and gas properties in China for $1.075 billion. The transaction is expected to close later in 2014 and is subject to preferential rights, regulatory approvals, and other customary closing conditions.

Property Exchange In 2013, the Company exchanged certain oil and gas properties in the Wattenberg field with a third party. The properties exchanged were measured at the Company's historical net cost with no gain or loss recognized. Anadarko paid $106 million in cash as part of the exchange, which is included as an addition to properties and equipment on the Company's Consolidated Statement of Cash Flows.

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

Assets Held for Sale During the fourth quarter of 2013, the Company began marketing certain domestic properties from the oil and gas exploration and production reporting segment to redirect its operating activities and capital investments to other areas. These assets were remeasured to their fair value using a market approach, resulting in a Level 2 fair-value measurement. Losses of $704 million primarily related to the sale of the Pinedale/Jonah assets in the Rockies, which closed in January 2014 for sale proceeds of $581 million. Gains and losses on assets held for sale are included in gains (losses) on divestitures and other, net in the Company's Consolidated Statements of Income. At December 31, 2013, the Company's Consolidated Balance Sheets included long-term assets of $616 million and long-term liabilities of $27 million associated with assets held for sale.

In 2012, the Company recognized losses on assets held for sale of $28 million primarily related to certain oil and gas exploration and production reporting segment properties. At December 31, 2012, the balances of assets and liabilities associated with assets held for sale were not material.

3. Inventories

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

millions	**2013**	2012
Crude oil	**$ 88**	$ 91
Natural gas	**43**	48
NGLs	**79**	37
Total	**$ 210**	$ 176

4. Properties and Equipment

The following summarizes the cost of properties and equipment by segment at December 31:

millions	**2013**	2012
Oil and gas exploration and production [(1)]	**$ 61,302**	$ 55,180
Midstream	**7,285**	6,032
Marketing	**9**	9
Other	**2,648**	2,377
Total	**$ 71,244**	$ 63,598

(1) Includes costs associated with unproved properties of $6.9 billion at December 31, 2013, and $7.1 billion at December 31, 2012.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

5. Impairments

The following summarizes impairments by segment for the years ended December 31:

millions	**2013**	2012	2011
Oil and gas exploration and production			
Long-lived assets held for use			
U.S. onshore properties	**$ 142**	$ 259	$ 1,063
Gulf of Mexico properties	**562**	104	162
Cost-method investment	**11**	13	91
Midstream			
Long-lived assets held for use	**79**	13	458
Impairments	**$ 794**	$ 389	$ 1,774

In 2013, certain Gulf of Mexico properties were impaired due to a reduction in estimated future net cash flows per barrel and downward revisions of reserves that the Company no longer plans to develop. Also in 2013, certain U.S. onshore properties and related midstream assets were impaired due to downward revisions of reserves that the Company no longer plans to develop. In addition, a midstream property was impaired during 2013 due to a reduction in estimated future cash flows. In 2012, certain U.S. onshore and midstream properties were impaired primarily due to lower natural-gas prices and Gulf of Mexico properties were impaired primarily as a result of downward reserves revisions for a property that was near the end of its economic life. In 2011, certain U.S. onshore and midstream properties were impaired primarily due to decreases in natural-gas prices, and Gulf of Mexico properties were impaired due to declines in estimated recoverable reserves. Impairments of the Company's Venezuelan cost-method investment were due to declines in estimated recoverable value.

The following summarizes the post-impairment fair value of the above-described assets, all of which were measured using the income approach and Level 3 inputs:

millions	**2013**	2012
Long-lived assets held for use	**$ 548**	$ 103
Cost-method investment [1]	**32**	34

[1] This represents the Company's after-tax net investment.

Impairments of Unproved Properties Impairments of unproved properties are included in exploration expense in the Company's Consolidated Statements of Income. In 2012, the Company recognized a $721 million impairment of unproved Powder River coalbed methane properties primarily due to lower natural-gas prices. Also in 2012, the Company recognized a $124 million impairment of an unproved Gulf of Mexico natural-gas property that the Company does not expect to develop under the forecasted natural-gas price environment.

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	**2013**	2012	2011
Balance at January 1	**$ 2,062**	$ 1,353	$ 935
Additions pending the determination of proved reserves	**848**	960	572
Divestitures	**(48)**	—	—
Reclassifications to proved properties	**(507)**	(129)	(116)
Charges to exploration expense	**(123)**	(122)	(38)
Balance at December 31	**$ 2,232**	$ 2,062	$ 1,353

The following summarizes an aging of suspended exploratory well costs by geographic area and the year the costs were suspended at December 31, 2013:

		Year Costs Incurred			
millions	**Total**	**2013[1]**	**2012**	**2011**	**2010 and prior**
United States—Onshore	$ 160	$ 143	$ 6	$ 1	$ 10
United States—Offshore	461	126	137	24	174
International	1,611	442	526	303	340
	$ 2,232	$ 711	$ 669	$ 328	$ 524

(1) Excludes additions subsequently reclassified to proved properties within the same year.

Suspended exploratory well costs capitalized for a period greater than one year after completion of drilling were associated with 14 projects at December 31, 2013, primarily located in Mozambique, Brazil, the Gulf of Mexico, and Ghana. Project costs suspended for longer than one year were primarily suspended pending the completion of economic evaluations including, but not limited to, results of additional appraisal drilling, well-test analysis, additional geological and geophysical data, facilities and infrastructure development options, development plan approval, and permitting. Management believes projects with suspended exploratory well costs exhibit sufficient quantities of hydrocarbons to justify potential development and is actively pursuing efforts to assess whether reserves can be attributed to these projects. 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. 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 during 2013 and 2012:

millions	**2013**	2012
Carrying amount of asset retirement obligations at January 1	**$ 1,885**	$ 1,768
Liabilities incurred	**182**	70
Property dispositions	**(76)**	(78)
Liabilities settled	**(162)**	(89)
Accretion expense	**110**	110
Revisions in estimated liabilities	**83**	104
Carrying amount of asset retirement obligations at December 31	**$ 2,022**	$ 1,885

8. Goodwill and Other Intangible Assets

Goodwill The Company completed its annual impairment assessment of goodwill during the fourth quarter of 2013, and the test indicated no impairment. At December 31, 2013, the Company had $5.5 billion of goodwill allocated to the following reporting units: $5.3 billion to oil and gas exploration and production, $70 million to other gathering and processing, $100 million to WES gathering and processing, and $5 million to transportation.

Significant declines in commodity prices, difficulty or potential delays in obtaining drilling permits, or other unanticipated events could result in further goodwill impairment tests in the near term, the results of which may have a material adverse impact on the Company's results of operations.

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

millions	**Gross Carrying Amount**	**Accumulated Amortization**	**Net Carrying Amount**	**Amortization Expense**
December 31, 2013				
Offshore platform leases	**$ 60**	**$ (50)**	**$ 10**	**$ 3**
Customer contracts	**169**	**(9)**	**160**	**4**
	$ 229	**$ (59)**	**$ 170**	**$ 7**
December 31, 2012				
Offshore platform leases	$ 60	$ (36)	$ 24	$ 3
Customer contracts	169	(5)	164	3
	$ 229	$ (41)	$ 188	$ 6

Customer contract intangible assets are primarily related to the 2011 Wattenberg Plant acquisition. The contracts are included in the Company's midstream reporting segment and are being amortized over 50 years. The estimated aggregate amortization expense for intangible assets for the next five years is not expected to be material.

9. Noncontrolling Interests

In December 2012, Western Gas Equity Partners, LP (WGP), a publicly traded consolidated subsidiary formed to own substantially all of Anadarko's partnership interests in WES, completed its initial public offering (IPO) of approximately 20 million common units representing limited partner interests in WGP at a price of $22.00 per common unit, for net proceeds of $411 million. At December 31, 2013, Anadarko's ownership interest in WGP consisted of a 91.0% limited partner interest and the entire non-economic general partner interest. The remaining limited partner interest in WGP consisted of a 9.0% public ownership interest.

WES, a publicly traded consolidated subsidiary, is a limited partnership formed by Anadarko to own, operate, acquire, and develop midstream assets. WES issued approximately 12 million common units to the public raising net proceeds of $725 million in 2013, approximately 5 million common units to the public raising net proceeds of $212 million in 2012, and approximately 10 million common units to the public raising net proceeds of $328 million in 2011. At December 31, 2013, WGP's ownership interest in WES consisted of a 41.2% limited partner interest, the entire 2.0% general partner interest, and all WES incentive distribution rights. At December 31, 2013, Anadarko also owned a 0.4% limited partner interest in WES through another subsidiary. The remaining limited partner interest in WES consisted of a 56.4% public ownership interest.

10. 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 London Interbank Offered Rate (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. 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, 2013. 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 investments and the obligations are presented net on the Consolidated Balance Sheets in other long-term liabilities—other for all periods presented.

Interest on the notes issued by Anadarko is variable, based on LIBOR, plus a spread that fluctuates with Anadarko's credit rating. The applicable interest rate was 1.24% at December 31, 2013, and 1.31% at December 31, 2012. The note payable agreement contains a covenant that provides for a maximum Anadarko debt-to-capital ratio of 67%. Anadarko was in compliance with this covenant at December 31, 2013. Other (income) expense, net includes interest expense on the notes payable of $37 million in 2013, $42 million in 2012, and $38 million in 2011, and equity earnings from Anadarko's investments in the investee entities of $(42) million in 2013, $(43) million in 2012, and $(41) million in 2011.

11. 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 Henry Hub, Louisiana for natural gas and Cushing, Oklahoma or Sullom Voe, Scotland for oil. 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 unfavorable interest-rate changes. The fair value of the Company's interest-rate swap portfolio increases (decreases) when interest rates increase (decrease).

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 14—Accumulated Other Comprehensive Income (Loss)*.

11. Derivative Instruments (Continued)

Oil and Natural-Gas Production/Processing Derivative Activities The natural-gas prices listed below are New York Mercantile Exchange (NYMEX) Henry Hub prices. The crude-oil prices listed below are a combination of NYMEX West Texas Intermediate and IntercontinentalExchange, Inc. (ICE) Brent Blend prices. The following is a summary of the Company's derivative instruments related to its Oil and Natural-Gas Production/Processing Activities at December 31, 2013:

	2014 Settlement	2015 Settlement
Natural Gas		
Three-Way Collars (thousand MMBtu/d)	600	635
Average price per MMBtu		
Ceiling sold price (call)	$ 5.01	$ 4.76
Floor purchased price (put)	$ 3.75	$ 3.75
Floor sold price (put)	$ 2.75	$ 2.75
Fixed-Price Contracts (thousand MMBtu/d)	600	—
Average price per MMBtu	$ 4.26	$ —
Extendable Fixed-Price Contracts (thousand MMBtu/d) (1)	400	—
Average price per MMBtu	$ 4.19	$ —
Crude Oil		
Fixed-Price Contracts (MBbls/d)	107	—
Average price per barrel	$ 100.58	$ —

(1) The extendable fixed-price contracts have a contract term of January 2014 to June 2014 with an option to extend the contract term to December 2014 at the same price.

MMBtu—million British thermal units
MMBtu/d—million British thermal units per day
MBbls/d—thousand barrels per day

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.

Marketing and Trading Derivative Activities The Company had financial derivative transactions with notional volumes totaling 16 billion cubic feet (Bcf) of natural gas at December 31, 2013, and 22 Bcf at December 31, 2012, that were entered into to mitigate commodity-price risk related to fixed-price purchase and sales contracts and storage activity.

11. Derivative Instruments (Continued)

Interest-Rate Derivatives In December 2008 and January 2009, Anadarko entered into interest-rate swap contracts as a fixed-rate payer to mitigate the interest-rate risk associated with anticipated future debt issuances. The Company locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR. The swap instruments include a provision that requires both the termination of the swaps and cash settlement in full at the start of the reference period.

To align the swap portfolio with the anticipated debt refinancing, the Company extended the maturity dates for certain interest-rate swaps. In 2012, the Company extended the maturity dates from October 2012 to September 2016 for interest-rate swaps with an aggregate notional principal amount of $800 million. In 2011, the Company extended the maturity dates from October 2011 to June 2014 for interest-rate swaps with an aggregate notional principal amount of $1.85 billion. In connection with these extensions, the swap interest rates were also adjusted. Interest-rate swap agreements with an aggregate notional principal amount of $200 million were settled in October 2012, resulting in a payment of $64 million, and interest-rate swap agreements with an aggregate notional principal amount of $150 million were settled in October 2011, resulting in a payment of $57 million.

The Company had the following outstanding interest-rate swaps at December 31, 2013:

millions except percentages		Reference Period		Weighted-Average
Notional Principal Amount		**Start**	**End**	**Interest Rate**
$	750	June 2014	June 2024	6.00%
$	1,100	June 2014	June 2044	5.57%
$	50	September 2016	September 2026	5.91%
$	750	September 2016	September 2046	5.86%

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	**2013**	2012	**2013**	2012
Commodity derivatives				
Other current assets	**$ 181**	$ 475	**$ (102)**	$ (197)
Other assets	**89**	24	**(66)**	(7)
Accrued expenses	**106**	6	**(149)**	(14)
Other liabilities	**4**	1	**(15)**	(7)
	380	506	**(332)**	(225)
Interest-rate and other derivatives				
Accrued expenses [(1)]	**—**	—	**(480)**	—
Other liabilities [(1)]	**—**	—	**(174)**	(1,194)
	—	—	**(654)**	(1,194)
Total derivatives	**$ 380**	$ 506	**$ (986)**	$ (1,419)

(1) Interest-rate swaps with June 2014 maturity dates were reclassified from other liabilities to accrued expenses during 2013.

11. Derivative Instruments (Continued)

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

millions **Classification of (Gain) Loss Recognized**	**2013**	2012	2011
Commodity derivatives			
Gathering, processing, and marketing sales [(1)]	**$ 6**	$ 18	$ 8
(Gains) losses on derivatives, net	**141**	(387)	(562)
Interest-rate and other derivatives			
(Gains) losses on derivatives, net	**(539)**	61	1,023
Total (gains) losses on derivatives, net	**$ (392)**	$ (308)	$ 469

(1) Represents the effect of marketing and trading derivative activities.

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 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 that provide for contract termination and net settlement across derivative types. At December 31, 2013, $76 million of the Company's $986 million gross derivative liability balance, and at December 31, 2012, $339 million of the Company's $1.4 billion gross derivative liability balance would have been eligible for setoff against the Company's gross derivative asset balance in the event of default. Other than in the event of default, the Company does not net settle across derivative types.

Some of the Company's derivative instruments are subject to provisions that can require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered. However, most of the Company's derivative counterparties maintain secured positions with respect to the Company's derivative liabilities under the Company's $5.0 billion senior secured revolving credit facility maturing in September 2015 ($5.0 billion Facility).

Unsecured derivative obligations may require immediate settlement or full collateralization if certain credit-risk-related provisions are triggered, such as the Company's credit rating from major credit rating agencies declining to a level below investment grade. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $42 million (net of collateral) at December 31, 2013, and $94 million (net of collateral) at December 31, 2012. The current portion of these amounts was included in accrued expenses and the long-term portion of these amounts was included in other long-term liabilities—other on the Company's Consolidated Balance Sheets.

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11. Derivative Instruments (Continued)

Fair Value Fair value of futures contracts is based on 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 the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, implied market volatility and discount factors. 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.

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, 2013						
Assets						
Commodity derivatives						
Financial institutions	**$ —**	**$ 211**	**$ —**	**$ (153)**	**$ —**	**$ 58**
Other counterparties	**—**	**169**	**—**	**(126)**	**—**	**43**
Total derivative assets	**$ —**	**$ 380**	**$ —**	**$ (279)**	**$ —**	**$ 101**
Liabilities						
Commodity derivatives						
Financial institutions	**$ —**	**$ (200)**	**$ —**	**$ 153**	**$ 7**	**$ (40)**
Other counterparties	**—**	**(132)**	**—**	**126**	**—**	**(6)**
Interest-rate and other derivatives	**—**	**(654)**	**—**	**—**	**—**	**(654)**
Total derivative liabilities	**$ —**	**$ (986)**	**$ —**	**$ 279**	**$ 7**	**$ (700)**
December 31, 2012						
Assets						
Commodity derivatives						
Financial institutions	$ 6	$ 453	$ —	$ (206)	$ —	$ 253
Other counterparties	—	47	—	(5)	—	42
Total derivative assets	$ 6	$ 500	$ —	$ (211)	$ —	$ 295
Liabilities						
Commodity derivatives						
Financial institutions	$ (6)	$ (202)	$ —	$ 206	$ 1	$ (1)
Other counterparties	—	(17)	—	5	—	(12)
Interest-rate and other derivatives	—	(1,194)	—	—	—	(1,194)
Total derivative liabilities	$ (6)	$ (1,413)	$ —	$ 211	$ 1	$ (1,207)

[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.

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12. Debt and Interest Expense

Debt The Company's outstanding debt is senior unsecured, except for borrowings, if any, under the $5.0 billion Facility. See *Note 10—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:

	December 31,	
millions	**2013**	2012
5.750% Senior Notes due 2014	**$ 275**	$ 275
7.625% Senior Notes due 2014	**500**	500
5.950% Senior Notes due 2016	**1,750**	1,750
6.375% Senior Notes due 2017	**2,000**	2,000
7.050% Debentures due 2018	**114**	114
WES 2.600% Senior Notes due 2018	**250**	—
6.950% Senior Notes due 2019	**300**	300
8.700% Senior Notes due 2019	**600**	600
WES 5.375% Senior Notes due 2021	**500**	500
WES 4.000% Senior Notes due 2022	**670**	670
6.950% Senior Notes due 2024	**650**	650
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
7.730% Debentures due 2096	**61**	61
7.500% Debentures due 2096	**78**	78
7.250% Debentures due 2096	**49**	49
Total debt at face value	**$ 15,202**	$ 14,952
Net unamortized discounts and premiums [(1)]	**(1,645)**	(1,683)
Total borrowings	**$ 13,557**	$ 13,269
Capital lease obligation	**8**	—
Less current portion of long-term debt	**500**	—
Total long-term debt	**$ 13,065**	$ 13,269

(1) Unamortized discounts and premiums are amortized over the term of the related debt.

12. Debt and Interest Expense (Continued)

In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing the Zero-Coupon Senior Notes due 2036 (Zero Coupons). The Zero Coupons mature in 2036 and have an aggregate principal amount due at maturity of $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, which would cause the Company to repay up to the then-accreted value of the outstanding Zero Coupons. The accreted value of the outstanding Zero Coupons was $727 million at December 31, 2013. Anadarko's $275 million aggregate principal amount of 5.750% Senior Notes due June 2014 and Zero Coupons, which can be put to the Company in 2014, are classified as long-term debt on the Company's Consolidated Balance Sheets, as the Company has the ability and intent to refinance these obligations using long-term debt.

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 $15.3 billion at December 31, 2013, and $16.2 billion at December 31, 2012.

Debt Activity The following summarizes the Company's debt activity during 2013 and 2012:

millions	Carrying Value	Description
Balance at December 31, 2011	$ 15,230	
Issuances	674	WES 4.000% Senior Notes due 2022
Borrowings	374	WES revolving credit facility
Repayments	(131)	6.125% Senior Notes due 2012
	(39)	5.000% Senior Notes due 2012
	(374)	WES revolving credit facility
	(2,500)	$5.0 billion Facility
Other, net	35	Amortization of debt discounts and premiums
Balance at December 31, 2012	$ 13,269	
Issuances	**250**	WES 2.600% Senior Notes due 2018
Borrowings	**710**	WES revolving credit facility
Repayments	**(710)**	WES revolving credit facility
Other, net	**38**	Amortization of debt discounts and premiums
Balance at December 31, 2013	**$ 13,557**	

12. Debt and Interest Expense (Continued)

Anadarko Revolving Credit Facility and Letter of Credit Facility In September 2010, the Company entered into the $5.0 billion Facility maturing in September 2015. Borrowings under the $5.0 billion Facility bear interest at LIBOR plus an applicable margin ranging from 1.25% to 2.50%, depending on the Company's credit rating, or rates at a margin above the one-month LIBOR, the federal funds rate, or prime rates offered by certain designated banks. During 2012, the Company repaid all outstanding borrowings under the $5.0 billion Facility with cash on hand and cash realized from the resolution of the Algeria exceptional profits tax dispute.

Obligations incurred under the $5.0 billion Facility, as well as obligations Anadarko has to lenders or their affiliates pursuant to certain derivative instruments that are supported by the $5.0 billion Facility (as discussed in *Note 11—Derivative Instruments*), are guaranteed by certain of the Company's wholly owned domestic subsidiaries, and are secured by a perfected first-priority security interest in certain exploration and production assets located in the United States and 65% of the capital stock of certain wholly owned foreign subsidiaries. At December 31, 2013, the Company was in compliance with applicable covenants and there were no restrictions on its ability to utilize the $5.0 billion Facility.

WES Borrowings In March 2011, WES entered into a five-year, $800 million senior unsecured revolving credit facility maturing in March 2016 (RCF). Borrowings under the RCF bear interest at LIBOR plus an applicable margin ranging from 1.30% to 1.90%, or rates at a margin above the one-month LIBOR, the federal funds rate, or prime rates offered by certain designated banks. During 2013, WES repaid all outstanding borrowings under its RCF with proceeds from debt and equity offerings. At December 31, 2013, WES was in compliance with all covenants contained in its RCF.

In February 2014, WES entered into a five-year, $1.2 billion senior unsecured revolving credit facility maturing in February 2019 (2014 RCF), which amended and restated the RCF. The 2014 RCF is expandable to a maximum of $1.5 billion. Borrowings under the 2014 RCF bear interest at LIBOR plus an applicable margin ranging from 0.975% to 1.45%, or rates at a margin above the one-month LIBOR, the federal funds rate, or prime rates offered by certain designated banks.

Scheduled Maturities Total principal amount of debt maturities for the five years ending December 31, 2018, excluding the potential repayment of the outstanding Zero Coupons that may be put by the holder to the Company annually, were as follows:

millions	**Principal Amount of Debt Maturities**
2014	$ 775
2015	—
2016	1,750
2017	2,000
2018	364

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

millions	**2013**	2012	2011
Current debt, long-term debt, and other	**$ 949**	$ 963	$ 986
Capitalized interest	**(263)**	(221)	(147)
Interest expense	**$ 686**	$ 742	$ 839

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13. Stockholders' Equity

Common Stock The following summarizes the changes in the Company's outstanding shares of common stock:

millions	**2013**	2012	2011
Shares of common stock issued			
Shares at January 1	**519**	516	513
Exercise of stock options	**2**	1	1
Issuance of restricted stock	**2**	2	2
Shares at December 31	**523**	519	516
Shares of common stock held in treasury			
Shares at January 1	**18**	18	17
Shares received for restricted stock vested and options exercised	**1**	—	1
Shares at December 31	**19**	18	18
Shares of common stock outstanding at December 31	**504**	501	498

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	**2013**	2012	2011
Net income (loss)			
Net income (loss) attributable to common stockholders	**$ 801**	$ 2,391	$ (2,649)
Less distributions on participating securities	**2**	1	—
Less undistributed income allocated to participating securities	**4**	14	—
Basic	**$ 795**	$ 2,376	$ (2,649)
Diluted	**$ 795**	$ 2,376	$ (2,649)
Shares			
Average number of common shares outstanding—basic	**502**	500	498
Dilutive effect of stock options	**3**	2	—
Average number of common shares outstanding—diluted	**505**	502	498
Excluded [(1)]	**4**	6	12
Net income (loss) per common share			
Basic	**$ 1.58**	$ 4.76	$ (5.32)
Diluted	**$ 1.58**	$ 4.74	$ (5.32)
Dividends per common share	**$ 0.54**	$ 0.36	$ 0.36

(1) Inclusion of certain shares would have had an anti-dilutive effect.

14. Accumulated Other Comprehensive Income (Loss)

The following summarizes the after-tax changes in the balances of each component 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, 2012	$ (61)	$ (579)	$ (640)
Other comprehensive income (loss), before reclassifications	**—**	**264**	**264**
Reclassifications to Consolidated Statement of Income	**7**	**84**	**91**
Net other comprehensive income (loss)	**7**	**348**	**355**
Balance at December 31, 2013	**$ (54)**	**$ (231)**	**$ (285)**

15. Share-Based Compensation

At December 31, 2013, 26 million shares of the 31 million shares of Anadarko common stock originally 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	**2013**	2012	2011
Equity-Classified Awards			
Restricted stock	**$ 122**	$ 103	$ 80
Stock options	**27**	43	51
Performance-based share awards and other	**1**	1	1
Total equity-classified award compensation expense	**150**	147	132
Liability-Classified Awards			
Value creation plan	**—**	(2)	26
Performance-based unit awards	**4**	8	28
Other performance-based awards	**—**	165	28
Other	**1**	2	1
Total liability-classified award compensation expense	**5**	173	83
Pretax compensation expense	**$ 155**	$ 320	$ 215
Income tax benefit	**$ 57**	$ 117	$ 78

Cash flows from financing activities included excess tax benefits related to share-based compensation of $11 million in 2013, $51 million in 2012, and $(15) million in 2011. Cash received from stock option exercises was $135 million in 2013, $52 million in 2012, and $45 million in 2011.

15. 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 up to three years and is not considered issued and outstanding 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 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, 2013	2.82	$ 79.27
Granted	1.88	$ 84.17
Vested	(1.32)	$ 78.19
Forfeited	(0.16)	$ 80.37
Non-vested at December 31, 2013	3.22	$ 82.53

The weighted-average grant-date fair value per share of restricted stock granted was $79.97 during 2012 and $81.19 during 2011. The total fair value of restricted shares vested was $110 million during 2013, $105 million during 2012, and $124 million during 2011, based on the market price at the vesting date. At December 31, 2013, total unrecognized compensation cost related to restricted stock of $175 million is expected to be recognized over a weighted-average remaining service period of 1.9 years.

15. Share-Based Compensation (Continued)

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 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. The expected life of an option is estimated based on historical exercise behavior. Volatility assumptions are estimated 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 are based on the U.S. Treasury rate over the expected life of an option. The dividend yield is based on a 12-month average dividend yield, taking into account the Company's expected dividend policy over the expected life of an option. Expected forfeiture rates are estimated based on historical forfeiture experience. The Company used the following weighted-average assumptions to estimate the fair value of stock options granted during 2013, 2012, and 2011:

	2013	2012	2011
Expected option life—years	**4.8**	4.9	4.8
Volatility	**33.9%**	44.2%	42.0%
Risk-free interest rate	**1.3%**	0.7%	1.5%
Dividend yield	**0.8%**	0.5%	0.5%

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, 2013	9.36	$ 58.66		
Granted	0.91	$ 91.71		
Exercised	(2.43)	$ 55.59		
Forfeited or expired	(0.12)	$ 74.55		
Outstanding at December 31, 2013	7.72	$ 63.30	3.59	$ 138.3
Vested or expected to vest at December 31, 2013	7.65	$ 63.14	3.57	$ 138.2
Exercisable at December 31, 2013	5.87	$ 57.00	2.83	$ 133.5

The per-option weighted-average grant-date fair value of stock options granted was $26.27 during 2013, $25.84 during 2012, and $29.77 during 2011. The total intrinsic value of stock options exercised was $80 million during 2013, $49 million during 2012, and $45 million during 2011, based on the difference between the market price at the exercise date and the exercise price. At December 31, 2013, total unrecognized compensation cost related to stock options of $41 million is expected to be recognized over a weighted-average remaining service period of 2.2 years.

15. Share-Based Compensation (Continued)

Performance-Based Share Awards In 2007, certain officers of the Company were provided Performance Unit Award Agreements with performance periods ranging from one to three years. The number of shares of common stock earned under these agreements was based on a comparison of the Company's TSR to the TSR of a predetermined group of peer companies over the specified performance periods. The maximum number of shares of Anadarko common stock available to be earned was 934,424 shares based on predefined payout percentages. At December 31, 2013, all performance periods have ended and a total of 521,258 shares were earned, with no additional shares available to be earned in the future. Of the total shares earned, 506,449 shares have been issued and 14,809 shares have been deferred pursuant to the agreements. The fair value of the performance-based share awards issued was $11 million during 2013, zero during 2012, and $6 million during 2011, based on the market price on the date of issuance. At December 31, 2013, the Company had no unrecognized compensation cost related to these awards.

Liability-Classified Awards

Value Creation Plan As a part of its employee compensation program, the Company offers an incentive compensation program that provides 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 zero during 2013 related to the plan, $24 million during 2012, and zero during 2011. At December 31, 2013, the Company had no outstanding liability attributable to the 2013 performance period.

Performance-Based Unit Awards Certain officers of the Company were provided Performance Unit Award Agreements with two- and 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. Each performance unit represents the value of one share of the Company's common stock. At the end of each performance period, the value of the vested performance units, if any, is paid in cash. The Company paid $15 million related to vested performance units in 2013, $37 million in 2012, and $25 million in 2011. At December 31, 2013, the Company's liability under Performance Unit Award Agreements was $15 million, with total unrecognized compensation cost related to these awards of $20 million expected to be recognized over a weighted-average remaining performance period of 1.9 years.

Other Performance-Based Awards Prior to 2011, certain officers of the general partner of WES were awarded general partner Unit Appreciation Rights (UARs) pursuant to the Western Gas Holdings, LLC Equity Incentive Plan. The fair value of the UARs was determined based on the fair value of WES's general partner, as determined by the WGP IPO price. The Company paid $203 million related to the UARs upon the WGP IPO in 2012 in settlement of obligations related to all awards then outstanding.

16. Commitments

Operating Leases At December 31, 2013, the Company had $3.3 billion in long-term drilling rig commitments that satisfy operating lease criteria. The Company also had $388 million of various commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, and aircraft. These operating leases expire at various dates through 2026. Certain of these operating leases contain residual value guarantees at the end of the lease term, totaling $53 million at December 31, 2013. No liability has been 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, 2013:

millions		
2014	$	964
2015		948
2016		755
2017		525
2018		309
Later years		189
Total future minimum lease payments	$	3,690

Total rent expense, net of sublease income, amounted to $119 million in 2013, $136 million in 2012, and $143 million in 2011. Total rent expense includes contingent rent expense related to processing fees of $17 million in 2013, $18 million in 2012, and $21 million in 2011.

Drilling Rig Commitments Anadarko has entered into various agreements to secure drilling rigs necessary to execute its drilling plans over the next several years. The table of future minimum lease payments above includes $3.1 billion related to eight offshore drilling vessels and $155 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.

Spar Platform and Production Vessel Leases Anadarko has operating leases related to certain spar platforms in the Gulf of Mexico. The table of future minimum lease payments above includes approximately $206 million for these agreements.

Other Commitments In the normal course of business, the Company enters into other contractual agreements for processing, treating, transportation, and storage of natural gas, crude oil, and NGLs, as well as for other oil and gas activities. These agreements expire at various dates through 2030. At December 31, 2013, aggregate future payments under these contracts totaled $11.5 billion, of which $2.3 billion is expected to be paid in 2014, $1.8 billion in 2015, $1.4 billion in 2016, $1.2 billion in 2017, $1.1 billion in 2018, and $3.7 billion thereafter.

17. Contingencies

Litigation 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, but not limited to, personal injury claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas 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. The Company's Consolidated Balance Sheets include liabilities of $854 million at December 31, 2013, and $49 million at December 31, 2012, 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, with the possible exception of the Tronox Litigation discussed below, the resolution of pending proceedings will not have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

Tronox Litigation On November 28, 2005, Tronox Incorporated (Tronox), at the time a subsidiary of Kerr-McGee Corporation, completed an IPO and was subsequently spun-off from Kerr-McGee Corporation. In August 2006, Anadarko acquired all of the stock of Kerr-McGee Corporation. In January 2009, Tronox and certain of Tronox's subsidiaries filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York (Bankruptcy Court), which is the court that is also hearing the Adversary Proceeding (defined below). Subsequently, in May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) asserting several claims, including claims for actual and constructive fraudulent conveyance (Adversary Proceeding). Tronox alleged, among other things, that it was insolvent or undercapitalized at the date of its IPO and sought, among other things, to recover damages from Kerr-McGee and Anadarko, as well as interest, appreciation, and attorneys' fees and costs. In accordance with Tronox's Bankruptcy Court-approved Plan of Reorganization (Plan), the Adversary Proceeding is being pursued by a litigation trust (Litigation Trust). Pursuant to the Plan, the Litigation Trust was "deemed substituted" for the Tronox plaintiffs in the Adversary Proceeding. For purposes of this Form 10-K, references to "Tronox" after February 2011 refer to the Litigation Trust.

The U.S. government intervened in the Adversary Proceeding, and in May 2009 asserted separate claims against Anadarko and Kerr-McGee under the Federal Debt Collection Procedures Act (FDCPA Complaint). The Litigation Trust and the U.S. government have agreed that the recovery of damages under the Adversary Proceeding, if any, would cover both the Adversary Proceeding and the FDCPA Complaint.

In February 2011, Tronox emerged from bankruptcy pursuant to the Plan. The terms of the Plan, which were confirmed by the Bankruptcy Court in the fourth quarter of 2010, contemplate that the claims of the U.S. government (together with other federal, state, local, and tribal governmental entities having regulatory authority or responsibilities for environmental laws, collectively, the Governmental Entities) related to Tronox's environmental liabilities and tort claims asserted against Tronox by other creditors will be settled through certain environmental response trusts and the Litigation Trust. The Plan provides for an allocation of any proceeds from the Adversary Proceeding between the Governmental Entities and the other creditors.

In January 2012, the Bankruptcy Court held that Section 550(a) of the Bankruptcy Code does not impose a cap on potential damages Tronox may recover, stating that the appropriate measure of damages should only be determined after trial in the Adversary Proceeding.

The Adversary Proceeding trial was held from May 2012 through September 2012. In November 2012, the parties filed post-trial briefs, and closing arguments were presented in December 2012. In December 2013, the Bankruptcy Court issued a *Memorandum of Opinion, After Trial* (discussed below).

17. Contingencies (Continued)

Historical Accounting The Company recognized losses of $250 million in the fourth quarter of 2011 and $275 million in the first quarter of 2012, for a total estimated contingent liability related to the Adversary Proceeding of $525 million at March 31, 2012. At that time, the Company's assessment was that it was probable the parties would reach a settlement and thus the Company considered a loss, via settlement, to be probable. The Company's attempts during the second quarter of 2012 to resolve the Adversary Proceeding through mediation and settlement discussions reached an impasse. Accordingly, based on information available at that time, the Company's assessment was that the likelihood of resolving the Adversary Proceeding through settlement was remote, that the likely form of final resolution of this matter was through litigation and the appellate process, and that a loss was not probable. Therefore, the Company reversed the settlement-based $525 million contingent liability in the second quarter of 2012 resulting in no accrued liability for this matter at June 30, 2012. There were no events or developments that changed the Company's assessment until December 2013.

Memorandum of Opinion In December 2013, the Bankruptcy Court issued a *Memorandum of Opinion, After Trial* (Opinion) in which the Bankruptcy Court found Kerr-McGee liable for fraudulent transfers in connection with Kerr-McGee's 2002 internal corporate restructuring and the subsequent IPO of Tronox. In its Opinion, the Bankruptcy Court concluded that damages from the fraudulent conveyance were equal to the value of the transferred assets as of the IPO date of $14.459 billion, but that Kerr-McGee may file a claim under Section 502(h) of the U.S. Bankruptcy Code (502(h) Claim). The Opinion provisionally outlined a framework for determining the amount of Kerr-McGee's 502(h) Claim, resulting in a 502(h) Claim amount of $10.459 billion. The Bankruptcy Court noted that a portion of the 502(h) Claim, if allowed, would be offset against an award of damages. The Bankruptcy Court expressed its opinion that it has the authority to enter a judgment against Kerr-McGee, but did not enter a judgment against Kerr-McGee at the time of the issuance of its Opinion because it had not resolved questions it raised concerning Kerr-McGee's 502(h) Claim and the portion of the 502(h) Claim that could be recovered (Recovery Percentage). The Bankruptcy Court also noted that attorneys' fees and costs could be added to an award to the extent appropriate. The Bankruptcy Court ordered the parties to submit further briefing regarding Kerr-McGee's 502(h) Claim.

Briefing on 502(h) Claim In accordance with the Bankruptcy Court's order, Kerr-McGee submitted its brief and filed its 502(h) Claim in January 2014 and the plaintiffs' response was submitted in February 2014. Kerr-McGee argued in its brief, among other things, that the Bankruptcy Court should not dilute Kerr-McGee's 502(h) Claim and that the Bankruptcy Court, in its provisional findings, has not properly considered the amount of Kerr-McGee's 502(h) Claim or the Recovery Percentage. Kerr-McGee argued that the proper application of the Bankruptcy Court's findings of fact and conclusions of law would result in net damages of $850 million. Alternatively, the Company argued that using the Bankruptcy Court's framework, damages should be limited to the net present value of the legacy environmental and tort liabilities at the IPO date, which the Bankruptcy Court determined to be $1.757 billion.

In their responsive pleadings, the plaintiffs argued, among other things, that Kerr-McGee's 502(h) Claim should be disallowed or, in the alternative, diluted to either 68% or 2.8% of its value. Furthermore, the plaintiffs argued that in addition to the value of the transferred assets as of the IPO date, they are entitled to recover appreciation in the value of those assets from the IPO date through June 2012, the date testimony was provided by a plaintiffs' expert. If combined with a disallowed 502(h) Claim as argued by the plaintiffs, this would yield net damages to the plaintiffs in the amount of $18.85 billion, excluding interest and attorneys' fees and costs. Further, the plaintiffs are seeking pre-judgment interest applied at a rate of 6% compounded annually from June 2012 through the date of judgment, which combined with the net damages amount above would total $20.77 billion as of February 2014. The plaintiffs also submitted a request to be reimbursed for $61 million in attorneys' fees and costs.

Kerr-McGee has until March 14, 2014, to submit a reply to the plaintiffs' brief. The Opinion indicated that either party may request a hearing on the matters being briefed, and a hearing has been scheduled for April 2014. After this process, the Bankruptcy Court is expected to issue a judgment, which will then be subject to appeal.

17. Contingencies (Continued)

Liability Accrual Analysis Applicable accounting guidance requires the Company to accrue a liability if (a) it is probable that a liability has been incurred and (b) the amount of that liability can be reasonably estimated. That guidance also requires a liability accrual at the low end of an estimated range of probable loss when no amount within the range is a better estimate than any other amount. The Company believes that a loss in the Adversary Proceeding is probable, based on the Bankruptcy Court's finding of liability in its Opinion. The Company considers a reasonable estimate of the range of probable loss, after all appellate processes have concluded, to be $850 million to $5.15 billion, and recorded a liability of $850 million, equal to the low end of that range. Although the Company does not believe a loss in excess of $5.15 billion to be probable, it is reasonably possible that the loss could be as high as $14.52 billion, including $61 million for attorneys' fees and costs, but excluding any potential interest and appreciation.

The Company's $850 million contingent liability accrual is based on the application of accounting guidance to currently available information and the Company's judgment concerning the application of law to that information. Furthermore, the Company's liability accrual and estimated range of probable loss do not include any amounts for interest, appreciation, or attorneys' fees and costs, and reflects its assessment that resolution through settlement is not probable at this time. The ultimate outcome of the Adversary Proceeding is subject to significant uncertainty; accordingly, the Company's liability accrual could change materially in the near term as events unfold and more information becomes available. In quantifying an estimated range of probable loss, the Company considered the following components of a possible award for which it could ultimately be responsible: damages, pre-judgment interest and appreciation, post-judgment interest, and attorneys' fees and costs.

Damages The Company estimates a range of probable damages ultimately awarded to the plaintiffs to be $850 million to $5.15 billion. This estimate is based on currently available information and the Company's opinion regarding the ultimate outcome of the Adversary Proceeding. As described below, the degree of uncertainty regarding the determination of Kerr-McGee's allowable 502(h) Claim and the Recovery Percentage prevents the Company from determining any one amount within the estimated range of probable loss to be a better estimate than any other amount.

Critical factors in assessing the estimated range of probable loss with respect to damages are the as-yet unresolved issues of the amount of Kerr-McGee's 502(h) Claim, and the extent to which such an offset amount would reduce damages. The Bankruptcy Court provisionally stated that the 502(h) Claim could be $10.459 billion. This 502(h) Claim amount represents the difference between (i) $14.459 billion, which is the Bankruptcy Court's finding as to damages based on the net value of the transferred assets as of the date of IPO, and (ii) $4.0 billion, which is the mid-point in the plaintiffs' post-petition estimate of potential legacy environmental and tort liabilities as of 2010. To calculate the offset amount that could reduce damages, the Bankruptcy Court indicated that the Recovery Percentage to be applied to Kerr-McGee's 502(h) Claim could be either 89% or 2.8%. The Bankruptcy Court noted in its Opinion that the Plan provides that Kerr-McGee's 502(h) Claim must be multiplied by "the percentage recovery to Allowed Class 3 General Unsecured Creditors" (Class 3 Recovery). Additionally, the Bankruptcy Court noted that 89% represents the estimated average Class 3 Recovery as stated in the Disclosure Statement filed by Tronox in its bankruptcy case. Under this scenario, the damages paid to the plaintiffs would be reduced by approximately $9.3 billion, resulting in a net damage award to plaintiffs of $5.15 billion.

The Bankruptcy Court also suggested that the Recovery Percentage might be determined after including Kerr-McGee's 502(h) Claim with the Class 3 claims allowed under the Plan, which would have the effect of diluting Kerr-McGee's Recovery Percentage. Under this scenario, the Recovery Percentage to be applied to Kerr-McGee's 502(h) Claim would be 2.8%, resulting in an allowed 502(h) Claim of $293 million and a net damages award to plaintiffs of approximately $14.16 billion.

The Company believes that Kerr-McGee's 502(h) Claim should be computed by reference to the Bankruptcy Court's own findings in the Opinion and the language of the Plan, as opposed to being computed by reference to the plaintiffs' post-petition estimate of the amount of legacy environmental and tort liabilities as of 2010. Accordingly, the Company believes that Kerr-McGee's 502(h) Claim should be computed by reference to $850 million, which represents the Bankruptcy Court's finding as to the amount of the net creditor shortfall at the IPO date, which considers the fair value of all of Tronox's assets and liabilities including the legacy environmental and tort liabilities.

17. Contingencies (Continued)

Using the Bankruptcy Court's framework for calculating the amount of Kerr-McGee's 502(h) Claim that may be allowed, but applying the Bankruptcy Court's finding of the $850 million net creditor shortfall instead of the plaintiffs' post-petition estimate of legacy environmental and tort liabilities used in the Bankruptcy Court's calculation, results in a 502(h) Claim of $13.609 billion. Furthermore, it is Kerr-McGee's position that the applicable Recovery Percentage should be determined by the Plan, which states that Kerr-McGee is entitled to the same Class 3 Recovery actually received in the bankruptcy, which exceeded 100%. In accordance with the principles of law and equity outlined in the Opinion, the Company believes that Kerr-McGee is entitled to a Recovery Percentage of 100%, resulting in a net damage award to plaintiffs of $850 million. While it is possible that damages could be determined using a Recovery Percentage of less than 89%, the Company does not believe that this outcome is probable, and therefore a lower Recovery Percentage is not included in the Company's estimated range of probable loss.

The following summarizes the Company's estimated range of probable loss:

billions, except percentages	Low End of Range of Probable Loss	High End of Range of Probable Loss
Value of Transferred Assets as of IPO date [1]	$ 14.459	$ 14.459
Net Creditor Shortfall/Legacy Liabilities	(0.850)	(4.000)
Allowable 502(h) Claim	$ 13.609	$ 10.459
Recovery Percentage	100%	89%
Offset Amount	$ 13.609	$ 9.309
Value of Transferred Assets as of IPO date [1]	$ 14.459	$ 14.459
Offset Amount	(13.609)	(9.309)
Net Damages	$ 0.850	$ 5.150

(1) As determined by the Bankruptcy Court.

The Company's estimate of the range of probable loss requires significant assumptions. As summarized above, the Company's estimated range of probable loss uses the net creditor shortfall of $850 million on the low end and plaintiffs' estimated legacy environmental and tort liabilities of $4.0 billion on the high end. Alternatively, the Bankruptcy Court could use $1.757 billion, which represents the Bankruptcy Court's findings of fact related to the net present value of the environmental and tort liabilities at the IPO date. Further, the Company's estimated range of probable loss uses a Recovery Percentage of 100% for the low end and 89% for the high end. Combinations of the above factors would result in damage estimates that are within the Company's estimated range of probable loss.

If no 502(h) Claim is allowed, the Company could incur a liability for damages of $14.459 billion, which is materially higher than the Company's estimated range of probable loss.

Pre-Judgment Interest and Appreciation The Bankruptcy Court did not address pre-judgment interest or appreciation in its Opinion. The Bankruptcy Court has discretion in deciding whether to award pre-judgment interest and how such interest may be calculated. The interest rate that may be charged, the date from which such interest is calculated, and whether any such interest is compounded or computed as simple interest may vary. If the Bankruptcy Court chooses to award pre-judgment interest, the amount could be material depending on the amount of net damages awarded in a judgment and the interest rates, dates, and compounding method applied for purposes of calculating the amount of pre-judgment interest.

17. Contingencies (Continued)

As noted above, the plaintiffs argued that, in addition to the value of the transferred assets as of 2005, the plaintiffs should recover appreciation in the value of those assets from November 2005 until June 2012. In connection with their appreciation argument, the plaintiffs also are seeking pre-judgment interest applied at a rate of 6% compounded annually from June 2012 until the date of judgment. Appreciation was not addressed by the Bankruptcy Court in its Opinion and it is unclear how any such argument by the plaintiffs will be addressed by the Bankruptcy Court, if at all.

The inherent uncertainty and lack of information, including the lack of a court-provided framework for whether or how the Bankruptcy Court would consider pre-judgment interest or appreciation, prevent the Company from formulating a reasonable estimate of the amount of pre-judgment interest or appreciation that could be included as part of a judgment. Accordingly, the Company is unable to estimate a range of probable or reasonably possible loss from pre-judgment interest or appreciation at this time, and the Company's liability accrual does not include any such amounts. The Company will continue to evaluate the extent to which a reasonable estimate of such amounts can be made as additional information regarding the above factors becomes available. Developments that could assist the Company in estimating interest or appreciation include a judgment by the Bankruptcy Court or matters raised in potential hearings regarding the remaining issues being briefed.

Post-Judgment Interest Post-judgment interest is mandated by federal law. Post-judgment interest would not begin to accrue until the date a judgment is entered, and would continue until that judgment is paid in full. Because no judgment had been issued as of December 31, 2013, a liability for post-judgment interest has not been incurred. Accordingly, no amount for post-judgment interest has been included in the Company's accrual or estimated range of probable loss. Further, the Company cannot estimate a range of future liability related to post-judgment interest at this time. At December 31, 2013, the annual interest rate for post-judgment interest was 0.13%.

Attorneys' Fees and Costs In its Opinion, the Bankruptcy Court stated that the plaintiffs could request reimbursement of attorneys' fees and costs. Based on the Company's review of relevant law, aside from certain de minimis costs the Company believes there is no basis in law or contract that would permit the plaintiffs to recover attorneys' fees and costs. Accordingly, the Company has not included any amount related to attorneys' fees and costs in its estimated range of probable loss. However, it is reasonably possible that a loss related to attorneys' fees and costs could be as high as the $61 million requested by the plaintiffs.

Tax Deductibility The Company has concluded that it is more likely than not that 88% of the $850 million loss recognized in 2013 will be deductible for U.S. tax purposes. Accordingly, the Company recognized a deferred tax benefit of $274 million in its 2013 financial statements. If additional losses are accrued in the future, the Company will evaluate the tax deductibility of any such accrual based on the facts and circumstances related to that accrual.

Liability Outlook A separate action pending before the U.S. Supreme Court to which Anadarko is not a party, *Executive Benefits Insurance Agency v. Arkison*, raises certain legal issues including, but not limited to, whether a bankruptcy court has authority to enter a judgment or to make a report and recommendation in a fraudulent transfer case. The Company is uncertain, at this time, what impact any ruling in that case would have on the Adversary Proceeding.

17. Contingencies (Continued)

As discussed above, the Company's $850 million accrued contingent liability as of December 31, 2013, has been established based on the application of accounting guidance to currently available information and the Company's judgment concerning the application of law to that information. A wide range of possible ultimate outcomes currently exists, and the Company may ultimately incur a liability related to the Adversary Proceeding materially in excess of the current accrued liability. The Company's liability accrual could also change materially in the near term as events unfold and more information becomes available. Further, it is possible that the Company's ultimate liability could exceed the currently estimated range of probable loss of $850 million to $5.15 billion. A judgment could also include an award of pre-judgment interest and appreciation, which could be material, as well as attorneys' fees and costs. In addition, the Company does not believe that the current contingent liability of $850 million accrued at December 31, 2013, is representative of the amount it could be required to pay to reach final resolution of the Adversary Proceeding through settlement. Although the Company does not believe final resolution through settlement to be probable at this time, it expects that any such settlement would require payment of an amount substantially greater than the current accrued liability.

Following a judgment, the Company would be required either to pay the damage award or appeal the judgment. If the Company pursues its rights through the appellate process, the Company may be required to post a bond or provide sufficient security to stay execution of the judgment by the plaintiffs pending the outcome of the appellate process. As the Bankruptcy Court has not yet issued a judgment, the Company is unable to estimate whether the Company would be required to provide a bond or other security or the potential form or amount of any such bond or other security. However, depending on the amount of the judgment and other factors relating to the appellate process, satisfying any security requirements could have a potentially material negative impact on the Company's consolidated financial position in the short term.

Deepwater Horizon Events In April 2010, the Macondo well in the Gulf of Mexico blew out and an explosion occurred on the *Deepwater Horizon* drilling rig, resulting in an oil spill. The well was operated by BP Exploration and Production Inc. (BP) and Anadarko held a 25% nonoperated interest. In October 2011, the Company and BP entered into a settlement agreement, mutual releases, and agreement to indemnify relating to the Deepwater Horizon events (Settlement Agreement), under which the Company paid $4.0 billion in cash and transferred its interest in the Macondo well and the Mississippi Canyon Block 252 (Lease) to BP. Pursuant to the Settlement Agreement, the Company is fully indemnified by BP against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and assessment costs, and any claims arising under the Operating Agreement with BP (OA). This indemnification is guaranteed by BP Corporation North America Inc. (BPCNA) and, in the event that the net worth of BPCNA declines below an agreed-upon amount, BP p.l.c. has agreed to become the sole guarantor. Under the Settlement Agreement, BP does not indemnify the Company against fines and penalties, punitive damages, shareholder derivative or securities laws claims, or certain other claims.

Liability Accrual Below is a discussion of the Company's current analysis, under applicable accounting guidance, of its potential liability for (i) amounts invoiced by BP under the OA (OA Liabilities), (ii) OPA-related environmental costs, and (iii) other contingent liabilities. Applicable accounting guidance requires the Company to accrue a liability if both (a) it is probable that a liability has been incurred and (b) the amount of that liability can be reasonably estimated.

The Company is fully indemnified by BP against OPA damage claims, NRD claims and assessment costs, and other potential liabilities. The Company may be required to recognize a liability for these amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recognized by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c. The Company has not recorded a liability for any costs that are subject to indemnification by BP.

17. Contingencies (Continued)

OA Liabilities Pursuant to the Settlement Agreement, all amounts deemed by BP to have been due under the OA, as well as all future amounts that otherwise would be invoiced to Anadarko under the OA, have been satisfied.

OPA-Related Environmental Costs BP, Anadarko, and other parties, including parties that do not own an interest in the Lease, such as the drilling contractor, have received correspondence from the U.S. Coast Guard (USCG) referencing their identification as a "responsible party or guarantor" (RP) under OPA. Under OPA, RPs, including Anadarko, may be jointly and severally liable for costs of well control, spill response, and containment and removal of hydrocarbons, as well as other costs and damage claims related to the spill and spill cleanup. The USCG's identification of Anadarko as an RP arises as a result of Anadarko's status as a co-lessee in the Lease.

Under accounting guidance applicable to environmental liabilities, a liability is presumed probable if the entity is both identified as an RP and associated with the environmental event. The Company's co-lessee status in the Lease at the time of the event and the subsequent identification and treatment of the Company as an RP satisfies these standards and therefore establishes the presumption that the Company's potential environmental liabilities related to the Deepwater Horizon events are probable.

As BP funds OPA-related environmental costs, any potential joint and several liability for these costs is satisfied for all RPs, including Anadarko. This bears significance in that once these costs are funded by BP, such costs are no longer analyzed as OPA-related environmental costs, but instead are analyzed as OA Liabilities. As discussed above, Anadarko has settled its OA Liabilities with BP. Thus, potential liability to the Company for OPA-related environmental costs can arise only where BP does not, or otherwise is unable to, fund all of the OPA-related environmental costs. Under this scenario, the joint and several nature of the liability for these costs could cause the Company to recognize a liability for OPA-related environmental costs. However, the Company is fully indemnified by BP against these costs (including guarantees by BPCNA or BP p.l.c.).

Gross OPA-Related Environmental Cost Estimate In prior periods through the fourth quarter of 2011, the Company provided an estimated range of gross OPA-related environmental costs for all identified RPs. This estimate was comprised of spill-response costs and OPA damage claims and was derived from cost information received by the Company from BP. The Company no longer receives Deepwater Horizon-related cost and claims data from BP. Accordingly, the OPA-related environmental cost estimate included in BP's public releases is the best data available to the Company.

Based on information included in BP p.l.c.'s public release on February 4, 2014, gross OPA-related environmental costs are estimated to be $10.9 billion, excluding (i) amounts BP has already funded, which constitute settled OA Liabilities; (ii) amounts that in BP's view cannot reasonably be estimated, which include NRD claims and other litigation damages; (iii) non-OPA-related fines and penalties that may be assessed against Anadarko, including assessments under the Clean Water Act (CWA); and (iv) estimated state and local governmental claims, which BP no longer publicly discloses and, as a result, Anadarko cannot estimate. Actual gross OPA-related environmental costs may vary from those estimated by BP p.l.c. in its public releases, perhaps materially from the above estimate.

17. Contingencies (Continued)

Allocable Share of Gross OPA-Related Environmental Costs Under applicable accounting guidance, the Company is required to estimate its allocable share of gross OPA-related environmental costs. To date, BP has paid all Deepwater Horizon event-related costs, which satisfies the Company's potential liability for these costs. Additionally, BP has repeatedly stated publicly and in congressional testimony that it will continue to pay these costs. BP's funding and public commentary has continued subsequent to the release of BP's own investigation report, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling's final report, and the Deepwater Horizon Joint Investigation Team final report, which the Company considers to be significant positive indications in assessing the likelihood of BP continuing to fund all of these costs. Based on BP's stated intent to continue funding these costs, the Company's assessment of BP's financial ability to continue funding these costs, and the impact of BP's settlements with both of its OA partners, the Company believes the likelihood of BP not continuing to satisfy these claims to be remote. Accordingly, the Company considers zero to be its allocable share of gross OPA-related environmental costs and, consistent with applicable accounting guidance, has not recorded a liability for these amounts.

Penalties and Fines These costs include amounts that may be assessed as a result of potential civil and/or criminal penalties under various federal, state, and/or local statutes and/or regulations as a result of the Deepwater Horizon events, including, for example, the CWA, the Outer Continental Shelf Lands Act, the Migratory Bird Treaty Act, and possibly other federal, state, and local laws. The foregoing does not represent an exhaustive list of statutes and regulations that potentially could trigger a penalty or fine assessment against the Company. To date, no penalties or fines have been assessed against the Company. However, in December 2010, the U.S. Department of Justice (DOJ), on behalf of the United States, filed a civil lawsuit in the U.S. District Court in New Orleans, Louisiana (Louisiana District Court) against several parties, including the Company, seeking an assessment of civil penalties under the CWA in an amount to be determined by the Louisiana District Court. In February 2012, the Louisiana District Court entered a declaratory judgment that, as a partial owner of the Macondo well, Anadarko is liable for civil penalties under Section 311 of the CWA. The declaratory judgment addresses liability only, and does not address the amount of any civil penalty. The assessment of a civil penalty against Anadarko has been reserved until a later proceeding to be scheduled by the Louisiana District Court. In August 2012, Anadarko filed a notice of appeal in the U.S. Court of Appeals for the Fifth Circuit concerning that portion of the February 2012 declaratory judgment finding Anadarko liable for civil penalties under the CWA. The appeal is pending and oral arguments were heard in December 2013. The Louisiana District Court has not yet issued a ruling.

As discussed below, numerous Deepwater Horizon event-related civil lawsuits have been filed against BP and other parties, including the Company. Certain state and local governments have appealed, or have provided indication of a likely appeal of, the Louisiana District Court's decision that only federal law, and not state law, applies to Deepwater Horizon event-related claims. For example, eleven Louisiana Parish District Attorneys appealed that decision to the U.S. Court of Appeals for the Fifth Circuit. In February 2014, the Fifth Circuit denied the appeal. If any such appeal is successful, state and/or local laws and regulations could become sources of penalties or fines against the Company.

17. Contingencies (Continued)

The Louisiana District Court's declaratory judgment in February 2012 satisfies the requirement that a loss, arising from the future assessment of a civil penalty against Anadarko, is probable. Notwithstanding the declaratory judgment, the Company currently cannot estimate the amount of any potential civil penalty. The CWA sets forth subjective criteria, including degree of fault and history of prior violations, which significantly influence the magnitude of CWA penalty assessments. As a result of the subjective nature of CWA penalty assessments, the Company currently cannot estimate the amount of any such penalty nor determine a range of potential loss. Furthermore, neither the February 2012 settlement of Deepwater Horizon-related civil penalties (including those under the CWA) by the other nonoperating partner with the United States and five affected Gulf states (Texas, Louisiana, Mississippi, Alabama, and Florida) nor the January 2013 settlement of CWA civil and criminal penalties by the drilling contractor with the United States affects the Company's current conclusion regarding its ability to estimate potential fines and penalties. The Company lacks insight into those settlements, retains legal counsel separate from the other parties, and was not involved in any manner with respect to those settlements. Events or factors that could assist the Company in estimating the amount of any potential civil penalty or a range of potential loss related to such penalties include (i) an assessment by the DOJ, (ii) a ruling by a court of competent jurisdiction, or (iii) the initiation of substantive settlement negotiations between the Company and the DOJ.

Given the Company's lack of direct operational involvement in the event, as was reconfirmed by the Louisiana District Court in September 2013 by excluding any evidence of Anadarko's alleged culpability or fault in the Phase II trial, and the subjective criteria of the CWA, the Company believes that its exposure to CWA penalties will not materially impact the Company's consolidated financial position, results of operations, or cash flows.

Natural Resource Damages This category includes future damage claims that may be made by federal and/or state natural resource trustee agencies at the completion of injury assessments and restoration planning. Natural resources generally include land, fish, water, air, wildlife, and other such resources belonging to, managed by, held in trust by, or otherwise controlled by, the federal, state, or local government.

The NRD-assessment process is led by government agencies that act as trustees of natural resources on behalf of the public. Government agencies involved in the process include the Department of Commerce, the Department of the Interior (DOI), and the Department of Defense. These governmental departments, along with the five affected states – Alabama, Florida, Louisiana, Mississippi, and Texas – are referred to as the "Co-Trustees." The Co-Trustees continue to conduct injury assessment and restoration planning.

The DOJ civil lawsuit filed against BP, the Company, and others seeks unspecified damages for injury to federal natural resources. Not all of the Co-Trustees were a party to this lawsuit; however, during the second quarter of 2011, the states of Alabama and Louisiana each filed NRD-related state law claims against the Company in the Louisiana District Court. In November 2011, the Louisiana District Court dismissed all the NRD-related state law claims asserted against the Company by the states of Alabama and Louisiana. In April 2013, the states of Texas and Mississippi filed NRD-related state law claims against the Company, which were consolidated in the federal Multidistrict Litigation (MDL) action before the Louisiana District Court discussed below and are stayed until further order of the Louisiana District Court.

NRD claims are generally sought after the damage assessment and restoration planning is completed, which may take several years. Thus, the Company remains unable to reasonably estimate the magnitude of any NRD claim. The Company anticipates that BP will satisfy any NRD claim, which eliminates any potential liability to Anadarko for such costs. In the event any NRD damage claim is made directly against Anadarko, the Company is fully indemnified by BP against such claims (including guarantees by BPCNA or BP p.l.c.).

17. Contingencies (Continued)

Civil Litigation Damage Claims Numerous Deepwater Horizon event-related civil lawsuits have been filed against BP and other parties, including the Company by, among others, fishing, boating, and shrimping enterprises and industry groups; restaurants; commercial and residential property owners; certain rig workers or their families; the States of Alabama, Louisiana, Texas, and Mississippi, and several of their political subdivisions; the DOJ; environmental non-governmental organizations; and certain Mexican states. Many of the lawsuits filed assert various claims of negligence, gross negligence, and violations of several federal and state laws and regulations, including, among others, OPA; the Comprehensive Environmental Response, Compensation, and Liability Act; the Clean Air Act; the CWA; and the Endangered Species Act; or challenge existing permits for operations in the Gulf of Mexico. Generally, the plaintiffs are seeking actual damages, punitive damages, declaratory judgment, and/or injunctive relief.

This litigation has been consolidated into a federal MDL action pending before Judge Carl Barbier in the Louisiana District Court. In March 2012, BP and the Plaintiffs' Steering Committee entered into a tentative settlement agreement to resolve the substantial majority of economic loss and medical claims stemming from the Deepwater Horizon events, which the Louisiana District Court approved in orders issued in December 2012 and January 2013. Only OPA claims seeking economic loss damages against the Company remain. In addition, certain state and local governments have appealed, or have provided indication of a likely appeal of, the Louisiana District Court's decision that only federal law, and not state law, applies to Deepwater Horizon event-related claims. Certain Mexican states also have appealed the dismissal of their claims against BP, the Company, and others. The Company, pursuant to the Settlement Agreement, is fully indemnified by BP against losses arising as a result of claims for damages, irrespective of whether such claims are based on federal (including OPA) or state law.

The first phase of the trial in the MDL commenced in February 2013 (Phase I). In April 2013, all parties rested their Phase I cases. Findings of fact, post-trial briefs, and responsive briefs were submitted in July 2013. BP, BP p.l.c., the United States, state and local governments, Halliburton Energy Services, Inc. (Halliburton), and Transocean Ltd. (Transocean) participated in Phase I. Anadarko was excused from participation in Phase I. The issues tried in Phase I included the cause of the blow-out and all related events leading up to April 22, 2010, the date the *Deepwater Horizon* sank, as well as allocation of fault. The allocation of fault remains in the Phase I trial because Halliburton and Transocean have not settled with any of the parties and each wishes to prove to the Louisiana District Court that their respective company was not at fault. The second phase of trial began in September 2013 (Phase II) and in November 2013 the parties rested their Phase II cases. The issues tried in Phase II included spill-source control and quantification of the spill for the period from April 20, 2010, until the well was capped. The Company, BP, BP p.l.c., the United States, state and local governments, Halliburton, and Transocean participated in Phase II of the trial. Prior to commencement of Phase II, the judge entered an order excluding any evidence of Anadarko's alleged culpability or fault during Phase II.

Two separate class action complaints were filed in June and August 2010, in the U.S. District Court for the Southern District of New York (New York District Court) on behalf of purported purchasers of the Company's stock between June 9, 2009, and June 12, 2010, against Anadarko and certain of its officers. The complaints allege causes of action arising pursuant to the Securities Exchange Act of 1934 for purported misstatements and omissions regarding, among other things, the Company's liability related to the Deepwater Horizon events. The plaintiffs seek an unspecified amount of compensatory damages, including interest thereon, as well as litigation fees and costs. In November 2010, the New York District Court consolidated the two cases. In March 2012, the New York District Court granted the plaintiffs' motion to transfer venue to the U.S. District Court for the Southern District of Texas - Houston Division (Texas District Court). In May 2012, the Texas District Court granted the defendants' motion to transfer the consolidated action within the district to Judge Keith P. Ellison. In July 2012, the plaintiffs filed their First Amended Consolidated Class Action Complaint. The defendants filed a renewed motion to dismiss in the Texas District Court in September 2012. In July 2013, the Texas District Court dismissed the claims relating to all but one of the alleged misstatements asserted in the plaintiffs' complaint. The Texas District Court gave the plaintiffs 30 days to amend the complaint to attempt to rehabilitate the claims that were dismissed. The plaintiffs declined to amend the complaint. The Company filed its answer to the complaint in September 2013. The parties have not commenced discovery.

17. Contingencies (Continued)

In September 2010, a purported shareholder made a demand on the Company's Board of Directors (the Board) to investigate allegations of breaches of duty by members of management related to the Deepwater Horizon events. The Board received a supplemental demand letter from the shareholder in March 2012. The Board considered each of the demand letters in January 2011 and April 2012 and determined that it would not be in the best interest of the Company to pursue the issues alleged in the demand letters. In May 2013, a shareholder derivative petition was filed in the 215th District Court of Harris County, Texas by the shareholder against Anadarko (as a nominal defendant) and certain current and former directors and officers. The petition alleges breach of fiduciary duties, unjust enrichment, abuse of control, and gross mismanagement in connection with the Deepwater Horizon events. The plaintiff seeks an unspecified amount of damages, certain changes to the Company's governance and internal procedures, disgorgement of profits, and reimbursement of litigation fees and costs. By agreement of the parties, this case has been stayed.

Given the various stages of these matters, the Company currently cannot assess the probability of losses, or reasonably estimate a range of any potential losses, related to ongoing proceedings. The Company intends to vigorously defend itself, its officers, and its directors in each of these matters, and will avail itself of the indemnities provided by BP against civil damages.

Remaining Liability Outlook It is possible that the Company may recognize additional Deepwater Horizon event-related liabilities for potential fines and penalties, shareholder claims, and certain other claims not covered by the indemnification provisions of the Settlement Agreement; however, the Company does not believe that any potential liability attributable to the foregoing items, individually or in the aggregate, will have a material impact on the Company's consolidated financial position, results of operations, or cash flows. This assessment takes into account certain qualitative factors, including the subjective and fault-based nature of CWA penalties, the Company's indemnification by BP against certain damage claims as discussed above, BP's creditworthiness, the merits of the shareholder claims, and directors' and officers' insurance coverage related to outstanding shareholder claims.

The Company will continue to monitor the MDL and other legal proceedings discussed above as well as federal investigations related to the Deepwater Horizon events. The Company cannot predict the nature of evidence that may be discovered during the course of legal proceedings or the timing of completion of any legal proceedings.

Although the Company is fully indemnified by BP against OPA damage claims, NRD claims and assessment costs, and certain other potential liabilities, the Company may be required to recognize a liability for these amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recognized by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c.

17. Contingencies (Continued)

Other 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. Currently, $144 million, the amount of tax originally in dispute, resides in a judicially controlled Brazilian bank account pending final resolution of the matter and is included in other assets on the Company's Consolidated Balance Sheet at December 31, 2013.

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 Brazilian Superior Court and the Brazilian Supreme Court have agreed to hear the case and the Company currently is awaiting the setting of initial hearing dates. 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 $47 million, the amount of tax currently in dispute, and any interest on such amount.

The Company believes that it will more likely than not prevail in Brazilian courts. Therefore, no tax liability has been recorded for Peregrino divestiture-related litigation at December 31, 2013. The Company continues to vigorously defend itself in Brazilian courts.

Algeria Exceptional Profits Tax Settlement In 2006, the Algerian parliament approved legislation establishing an exceptional profits tax on foreign companies' Algerian oil production and issued regulations implementing this legislation. The Company disagreed with Sonatrach's collection of the exceptional profits tax and initiated arbitration against Sonatrach in 2009. In March 2012, the Company and Sonatrach resolved this dispute and the resolution provided for the transfer of $1.7 billion of crude oil to the Company over a 12-month period ending in mid-2013.

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. In 2013, as a result of a bankruptcy declaration by a third party, the DOI ordered Anadarko to decommission offshore wells and production facilities previously sold to the third party and not related to the Company's current operations. During 2013, the Company recognized a decommissioning charge of $117 million, reported in other (income) expense, net in the Consolidated Statement of Income. Anadarko expects to complete decommissioning of the production facilities in 2014 and the wells in 2015. Decommissioning obligations of $21 million were included in accrued expenses and $85 million were included in other long-term liabilities on the Consolidated Balance Sheet at December 31, 2013. Actual costs may vary from this estimate; however, the Company does not believe that any such change will materially impact its consolidated financial position, results of operations, or cash flows.

17. Contingencies (Continued)

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 of $126 million at December 31, 2013, and $81 million at December 31, 2012, for remediation and reclamation obligations. The current portion of these amounts was included in accounts payable 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.

The Company was previously notified by the California Department of Toxic Substances Control (DTSC) that, as a result of a prior acquisition, it is one of 27 potentially responsible parties with respect to a landfill located in West Covina, California. While no agreement is in place with the DTSC, the Company has recorded a $50 million restoration liability with respect to the site, representing the current estimated obligation, which is included in the Company's liability balance at December 31, 2013. The Company could incur additional obligations if any of the potentially responsible parties are ultimately not able to fund their allocated share of the costs or if the DTSC requires a more costly remedial approach. It is possible that the Company's current estimate of probable loss related to this matter could change, perhaps materially, in the future.

18. Other Taxes

Taxes incurred, other than income taxes, for the years ended December 31 were as follows:

millions	**2013**	2012	2011
Production and severance	**$ 706**	$ 855	$ 1,094
Ad valorem	**277**	238	265
Other	**94**	131	133
Total	**$ 1,077**	$ 1,224	$ 1,492

19. Income Taxes

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

millions	**2013**	2012	2011
Current			
Federal	**$ 113**	$ 45	$ (381)
State	**42**	25	1
Foreign	**873**	891	977
	1,028	961	597
Deferred			
Federal	**94**	(30)	(1,470)
State	**(9)**	115	(68)
Foreign	**52**	74	85
	137	159	(1,453)
Income tax expense (benefit)	**$ 1,165**	$ 1,120	$ (856)

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	**2013**	2012	2011
Income (loss) before income taxes			
Domestic	**$ 428**	$ 132	$ (5,416)
Foreign	**1,678**	3,433	1,992
Total	**$ 2,106**	$ 3,565	$ (3,424)
U.S. federal statutory tax rate	**35%**	35%	35%
Tax computed at the U.S. federal statutory rate	**$ 737**	$ 1,248	$ (1,198)
Adjustments resulting from			
State income taxes (net of federal income tax benefit)	**23**	93	(44)
Tax impact from foreign operations	**167**	226	93
Non-deductible Algerian exceptional profits tax	**144**	188	258
Non-taxable Algeria exceptional profits tax settlement	**13**	(679)	—
Deferred tax adjustments	**76**	22	5
Non-deductible Tronox-related contingent loss	**36**	—	—
Income attributable to noncontrolling interests	**(48)**	(24)	(28)
Items resulting from business acquisitions	**—**	—	19
Other—net	**17**	46	39
Income tax expense (benefit)	**$ 1,165**	$ 1,120	$ (856)
Effective tax rate	**55%**	31%	25%

19. Income Taxes (Continued)

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

millions	**2013**	2012
Federal	**$ (8,246)**	$ (7,890)
State, net of federal	**(332)**	(325)
Foreign	**(307)**	(216)
Total deferred taxes	**$ (8,885)**	$ (8,431)

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

millions	**2013**	2012
Current deferred tax assets	**$ 412**	$ 328
Valuation allowances on deferred tax assets not expected to be realized	**(52)**	—
Net current deferred tax assets	**360**	328
Oil and gas exploration and development operations	**(8,213)**	(8,683)
Mineral operations	**(410)**	(408)
Midstream and other depreciable properties	**(1,586)**	(1,295)
Other	**(499)**	(152)
Gross long-term deferred tax liabilities	**(10,708)**	(10,538)
Oil and gas exploration and development costs	**94**	762
Net operating loss carryforward	**599**	477
Foreign tax credit carryforward and alternative minimum tax credit carryforward	**325**	450
Other	**1,211**	1,012
Gross long-term deferred tax assets	**2,229**	2,701
Valuation allowances on deferred tax assets not expected to be realized	**(766)**	(922)
Net long-term deferred tax assets	**1,463**	1,779
Net long-term deferred tax liabilities	**(9,245)**	(8,759)
Total deferred taxes	**$ (8,885)**	$ (8,431)

Changes to valuation allowances, due to changes in judgment regarding the future realizability of deferred tax assets, were an increase of $2 million in 2013, an increase of $23 million in 2012, and a decrease of $17 million in 2011. The following summarizes changes in the balance of valuation allowances on deferred tax assets:

millions	**2013**	2012	2011
Balance at January 1	**$ (922)**	$ (555)	$ (454)
Additions	**(38)**	(426)	(138)
Reductions	**142**	59	37
Balance at December 31	**$ (818)**	$ (922)	$ (555)

19. Income Taxes (Continued)

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

Balance Sheet Classification	2013	2012
Income taxes receivable		
Accounts receivable—other	**$ 66**	$ 179
Other assets	**35**	2
	101	181
Income taxes (payable)		
Accrued expense	**(82)**	(38)
Net income taxes receivable (payable)	**$ 19**	$ 143

Tax carryforwards available for use on future income tax returns at December 31, 2013, were as follows:

millions	Domestic	Foreign	Expiration
Net operating loss—foreign	$ —	$ 1,265	2014 - Indefinite
Net operating loss—state	$ 4,527	$ —	2014-2032
Foreign tax credits	$ 325	$ —	2015-2023
Texas margins tax credit	$ 35	$ —	2026

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

	Assets (Liabilities)		
millions	2013	2012	2011
Balance at January 1	**$ (46)**	$ (31)	$ (32)
Increases related to prior-year tax positions	**(54)**	(17)	—
Decreases related to prior-year tax positions	**3**	3	3
Increases related to current-year tax positions	**(72)**	(1)	(10)
Settlements	**5**	—	8
Lapse of statute of limitations	**17**	—	—
Balance at December 31	**$ (147)**	$ (46)	$ (31)

Included in the 2013 ending balance of unrecognized tax benefits presented above are potential benefits of $(129) million that would affect the effective tax rate on income if recognized. Based on the Company's existing activities, a $99 million increase in valuation allowance would be expected to offset a portion of the potential benefit of $(129) million. Also included in the 2013 ending balance are benefits of $(18) million related to tax positions for which the ultimate deductibility is highly certain, but the timing of such deductibility is uncertain. The Company estimates that $(4) million to $(10) million of unrecognized tax benefits related to adjustments to taxable income and credits previously recorded pursuant to the accounting standard for accounting for tax uncertainties will reverse within the next 12 months due to expiration of statutes of limitation and audit settlements.

The Company had accrued approximately $8 million of interest related to uncertain tax positions at December 31, 2013, and $28 million at December 31, 2012. The Company recognized interest and penalties in income tax expense (benefit) of $(20) million during 2013 and $9 million during 2012.

19. Income Taxes (Continued)

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 Company is currently under routine examination by the U.S. Internal Revenue Service for the tax years 2007 through 2013.

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—Other Litigation.* Management does not believe that the final resolution of outstanding tax audits and litigation will have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

The following lists the tax years subject to examination by major tax jurisdiction:

	Tax Year
United States	2007-2013
China	2009-2013
Algeria	2010-2013
Ghana	2006-2013

20. Supplemental Cash Flow Information

The following summarizes cash paid (received) for interest (net of amounts capitalized) and income taxes, as well as non-cash investing and financing transactions for the years ended December 31:

millions	**2013**	2012	2011
Cash paid (received)			
Interest	**$ 627**	$ 684	$ 806
Income taxes	**169**	(300)	262
Non-cash investing activities			
Fair value of properties and equipment exchanged in non-cash transactions	**$ 62**	$ 65	$ 19
Gain related to the fair-value remeasurement of Anadarko's pre-acquisition 7% equity interest in the Wattenberg Plant	**—**	—	21
Non-cash investing and financing activities			
Capital lease obligation	**$ 8**	$ —	$ (118)
Floating production, storage, and offloading vessel construction period obligation	**17**	—	—

21. Segment Information

Anadarko's business segments are separately managed due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are oil and gas exploration and production, midstream, and marketing. The oil and gas exploration and production segment explores for and produces natural gas, crude oil, condensate, and NGLs, and plans for the development and operation of the Company's LNG project in Mozambique. The midstream segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production. The midstream reporting segment consists of two operating segments, WES and other midstream, which are aggregated into one reporting segment due to similar financial and operating characteristics. The marketing segment sells much of Anadarko's production, as well as third-party purchased volumes.

21. Segment Information (Continued)

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; exploration expense; depreciation, depletion, and amortization (DD&A); impairments; interest expense; total (gains) losses on derivatives, net, less net cash received in settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income attributable to noncontrolling interests. During the periods presented, certain items not related to the Company's normal operations included Deepwater Horizon settlement and related costs, Algeria exceptional profits tax settlement, Tronox-related contingent loss, and certain other nonoperating items included in other (income) expense, net. The Company's definition of Adjusted EBITDAX excludes exploration expense, as it is not an indicator of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, 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 received in 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 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.

Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders. 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 or cash flows from operating activities. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes for the years ended December 31:

millions	**2013**	2012	2011
Income (loss) before income taxes	**$ 2,106**	$ 3,565	$ (3,424)
Exploration expense	**1,329**	1,946	1,076
DD&A	**3,927**	3,964	3,830
Impairments	**794**	389	1,774
Interest expense	**686**	742	839
Total (gains) losses on derivatives, net, less net cash received in settlement of commodity derivatives	**(307)**	443	675
Deepwater Horizon settlement and related costs	**15**	18	3,930
Algeria exceptional profits tax settlement	**33**	(1,797)	—
Tronox-related contingent loss	**850**	(250)	250
Certain other nonoperating items	**110**	—	—
Less net income attributable to noncontrolling interests	**140**	54	81
Consolidated Adjusted EBITDAX	**$ 9,403**	$ 8,966	$ 8,869

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

21. Segment Information (Continued)

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 U.S. Generally Accepted Accounting Principles (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.

Information presented below as "Other and Intersegment Eliminations" includes results from hard-minerals royalty arrangements and corporate, financing, and certain derivative activities. The following summarizes selected financial information for Anadarko's reporting segments:

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2013					
Sales revenues	$ 7,090	$ 387	$ 7,390	$ —	$ 14,867
Intersegment revenues	6,405	1,105	(6,859)	(651)	—
Gains (losses) on divestitures and other, net	(622)	(1)	—	337	(286)
Total revenues and other	12,873	1,491	531	(314)	14,581
Operating costs and expenses [1]	3,635	843	652	20	5,150
Net cash received in settlement of commodity derivatives	—	—	—	(95)	(95)
Other (income) expense, net [2]	—	—	—	(21)	(21)
Net income attributable to noncontrolling interests	—	140	—	—	140
Total expenses and other	3,635	983	652	(96)	5,174
Total (gains) losses on derivatives, net included in marketing revenue, less net cash received in settlement	—	—	(4)	—	(4)
Adjusted EBITDAX	$ 9,238	$ 508	$ (125)	$ (218)	$ 9,403
Net properties and equipment	$ 33,409	$ 5,408	$ 9	$ 2,103	$ 40,929
Capital expenditures	$ 7,008	$ 1,248	$ —	$ 267	$ 8,523
Goodwill	$ 5,317	$ 175	$ —	$ —	$ 5,492

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

21. Segment Information (Continued)

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2012					
Sales revenues	$ 6,752	$ 325	$ 6,230	$ —	$ 13,307
Intersegment revenues	5,318	959	(5,734)	(543)	—
Gains (losses) on divestitures and other, net	(65)	(8)	—	177	104
Total revenues and other	12,005	1,276	496	(366)	13,411
Operating costs and expenses [1]	3,505	748	616	295	5,164
Net cash received in settlement of commodity derivatives	—	—	—	(753)	(753)
Other (income) expense, net [2]	—	—	—	(4)	(4)
Net income attributable to noncontrolling interests	—	54	—	—	54
Total expenses and other	3,505	802	616	(462)	4,461
Total (gains) losses on derivatives, net included in marketing revenue, less net cash received in settlement	—	—	16	—	16
Adjusted EBITDAX	$ 8,500	$ 474	$ (104)	$ 96	$ 8,966
Net properties and equipment	$ 32,024	$ 4,459	$ 9	$ 1,906	$ 38,398
Capital expenditures	$ 5,906	$ 1,250	$ —	$ 155	$ 7,311
Goodwill	$ 5,317	$ 175	$ —	$ —	$ 5,492
2011					
Sales revenues	$ 7,519	$ 342	$ 6,023	$ (2)	$ 13,882
Intersegment revenues	5,005	957	(5,515)	(447)	—
Gains (losses) on divestitures and other, net	(41)	(13)	—	139	85
Total revenues and other	12,483	1,286	508	(310)	13,967
Operating costs and expenses [1]	3,696	786	559	186	5,227
Net cash received in settlement of commodity derivatives	—	—	—	(226)	(226)
Other (income) expense, net [2]	—	—	—	4	4
Net income attributable to noncontrolling interests	—	81	—	—	81
Total expenses and other	3,696	867	559	(36)	5,086
Total (gains) losses on derivatives, net included in marketing revenue, less net cash received in settlement	—	—	(12)	—	(12)
Adjusted EBITDAX	$ 8,787	$ 419	$ (63)	$ (274)	$ 8,869
Net properties and equipment	$ 32,235	$ 3,432	$ 9	$ 1,825	$ 37,501
Capital expenditures	$ 5,026	$ 1,420	$ —	$ 107	$ 6,553
Goodwill	$ 5,475	$ 166	$ —	$ —	$ 5,641

(1) Operating costs and expenses exclude exploration expense, DD&A, impairments, Deepwater Horizon settlement and related costs, and Algeria exceptional profits tax settlement since these expenses are excluded from Adjusted EBITDAX.

(2) Other (income) expense, net excludes Tronox-related contingent loss since this expense is excluded from Adjusted EBITDAX.

21. 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	**2013**	2012	2011
Sales Revenues			
United States	**$ 11,290**	$ 9,911	$ 10,477
Algeria	**2,184**	2,182	2,258
Other International	**1,393**	1,214	1,147
Total	**$ 14,867**	$ 13,307	$ 13,882

	December 31,	
millions	**2013**	2012
Net Properties and Equipment		
United States	**$ 35,486**	$ 33,337
Algeria	**1,582**	1,575
Other International	**3,861**	3,486
Total	**$ 40,929**	$ 38,398

Major Customers Sales to Total S.A. were $2.0 billion in 2013 and $1.9 billion in 2012. These amounts are included in the oil and gas exploration and production reporting segment. In 2011, there were no sales to individual customers that exceeded 10% of the Company's total sales revenues.

22. 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.

While reported benefit obligations exceed the fair value of pension and other postretirement plan assets at December 31, 2013, the Company monitors the funded status of its funded pension plans to ensure that plan funds are sufficient to continue paying benefits. During 2013, the Company made contributions of $123 million to its funded pension plans, $37 million to its unfunded pension plans, and $14 million to its unfunded other postretirement benefit plans. Contributions to funded plans increase plan assets while contributions to unfunded plans are used to fund current benefit payments. The Company expects to contribute $103 million to its funded pension plans, $19 million to its unfunded pension plans, and $15 million to its unfunded other postretirement benefit plans in 2014.

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

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, 2013 and 2012, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2013 and 2012:

	Pension Benefits		Other Benefits	
millions	**2013**	2012	**2013**	2012
Change in benefit obligation				
Benefit obligation at beginning of year	**$ 2,297**	$ 2,024	**$ 359**	$ 354
Service cost	**85**	76	**9**	9
Interest cost	**78**	85	**14**	16
Actuarial (gain) loss	**(156)**	224	**(74)**	(1)
Participant contributions	**—**	1	**4**	3
Benefit payments	**(149)**	(117)	**(18)**	(22)
Foreign-currency exchange-rate changes	**3**	4	**—**	—
Benefit obligation at end of year [(1)]	**$ 2,158**	$ 2,297	**$ 294**	$ 359
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,462**	$ 1,308	**$ —**	$ —
Actual return on plan assets	**278**	159	**—**	—
Employer contributions	**160**	107	**14**	19
Participant contributions	**—**	1	**4**	3
Benefit payments	**(149)**	(117)	**(18)**	(22)
Foreign-currency exchange-rate changes	**3**	4	**—**	—
Fair value of plan assets at end of year	**$ 1,754**	$ 1,462	**$ —**	$ —
Funded status of the plans at end of year	**$ (404)**	$ (835)	**$ (294)**	$ (359)
Total recognized amounts in the balance sheet consist of				
Other assets	**$ 37**	$ 30	**$ —**	$ —
Accrued expenses	**(19)**	(44)	**(15)**	(16)
Other long-term liabilities—other	**(422)**	(821)	**(279)**	(343)
Total	**$ (404)**	$ (835)	**$ (294)**	$ (359)
Total recognized amounts in accumulated other comprehensive income consist of				
Prior service cost (credit)	**$ (1)**	$ (2)	**$ 2**	$ 3
Net actuarial (gain) loss	**441**	916	**(78)**	(4)
Total	**$ 440**	$ 914	**$ (76)**	$ (1)

(1) The accumulated benefit obligation for all defined-benefit pension plans was $1.8 billion at December 31, 2013, and $2.1 billion at December 31, 2012.

22. 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	**2013**	2012
Projected benefit obligation	**$ 2,047**	$ 2,198
Accumulated benefit obligation	**1,742**	2,054
Fair value of plan assets	**1,606**	1,333

The following summarizes the Company's pension and other postretirement benefit cost and amounts recognized in other comprehensive income (before tax benefit) for the years ended December 31:

	Pension Benefits			**Other Benefits**		
millions	**2013**	2012	2011	**2013**	2012	2011
Components of net periodic benefit cost						
Service cost	**$ 85**	$ 76	$ 78	**$ 9**	$ 9	$ 9
Interest cost	**78**	85	85	**14**	16	16
Expected return on plan assets	**(91)**	(91)	(85)	**—**	—	—
Amortization of net actuarial loss (gain)	**118**	93	85	**—**	—	—
Amortization of net prior service cost (credit)	**—**	—	2	**1**	2	—
Settlement loss	**14**	—	—	**—**	—	—
Net periodic benefit cost	**$ 204**	$ 163	$ 165	**$ 24**	$ 27	$ 25
Amounts recognized in other comprehensive income (expense)						
Net actuarial gain (loss)	**$ 342**	$ (156)	$ (183)	**$ 74**	$ 1	$ (30)
Amortization of net actuarial (gain) loss	**118**	93	85	**—**	—	—
Net prior service (cost) credit	**—**	—	12	**—**	—	—
Amortization of net prior service cost (credit)	**—**	—	2	**1**	2	—
Settlement loss	**14**	—	—	**—**	—	—
Total amounts recognized in other comprehensive income (expense)	**$ 474**	$ (63)	$ (84)	**$ 75**	$ 3	$ (30)

In 2014, an estimated $26 million of net actuarial loss for the pension and other postretirement plans will be amortized from accumulated other comprehensive income into net periodic benefit cost.

The following summarizes the weighted-average assumptions used by the Company in determining the pension and other postretirement benefit obligations at December 31:

	Pension Benefits		**Other Benefits**	
	2013	2012	**2013**	2012
Discount rate	**4.75%**	3.50%	**5.25%**	4.00%
Rates of increase in compensation levels	**5.00%**	4.50%	**5.25%**	4.50%

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

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 net periodic pension and other postretirement benefit cost:

	Pension Benefits			Other Benefits		
	2013	2012	2011	**2013**	2012	2011
Discount rate	**3.50%**	4.50%	4.75%	**4.00%**	4.75%	5.25%
Long-term rate of return on plan assets	**7.00%**	7.00%	7.00%	**N/A**	N/A	N/A
Rates of increase in compensation levels	**4.50%**	4.50%	5.00%	**4.50%**	4.50%	5.00%

At December 31, 2013, an 8.00% annual rate of increase in the per-capita cost of covered health care benefits for 2014 was assumed for purposes of measuring other postretirement benefit obligations. At December 31, 2012, an 8.00% annual rate of increase in the per-capita cost of covered health care benefits for 2013 was assumed for purposes of measuring other postretirement benefit obligations. This rate is expected to gradually decrease to 5.00% in 2019 and beyond. The assumed health care cost trend rate can have a significant effect on the cost and obligation amounts reported for the health care plan. A 1% change in the assumed health care cost trend rate over the projected period would have the following effects:

millions	1% Increase	1% Decrease
Effect on total of service and interest cost components	$ 3	$ (2)
Effect on other postretirement benefit obligation	$ 23	$ (20)

22. 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 2013 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, and inflation. Returns on fixed-income securities are generally developed based on expected inflation, real bond yield, and risk spread (as appropriate), adjusted for the expected effect that changing yields have on the rate of return. Other asset-class returns are derived from their relationship to the equity and fixed-income markets.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2013, 2012, AND 2011

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

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, 2013	Level 1	Level 2	Level 3	Total
Investments				
Cash and cash equivalents	**$ 17**	**$ 80**	**$ —**	**$ 97**
Fixed income				
Mortgage-backed securities	**—**	**54**	**—**	**54**
U.S. government securities	**—**	**52**	**—**	**52**
Other fixed-income securities [1]	**42**	**197**	**—**	**239**
Equity securities				
Domestic	**445**	**116**	**—**	**561**
International	**148**	**303**	**—**	**451**
Other				
Real estate	**—**	**47**	**86**	**133**
Private equity	**—**	**—**	**72**	**72**
Hedge funds and other alternative strategies	**31**	**—**	**79**	**110**
Total investments [2]	**$ 683**	**$ 849**	**$ 237**	**$ 1,769**
Liabilities				
Hedge funds and other alternative strategies	**$ (17)**	**$ —**	**$ —**	**$ (17)**
Total liabilities	**$ (17)**	**$ —**	**$ —**	**$ (17)**
December 31, 2012				
Investments				
Cash and cash equivalents	$ 23	$ 36	$ —	$ 59
Fixed income				
Mortgage-backed securities	—	63	—	63
U.S. government securities	—	54	—	54
Other fixed-income securities [1]	40	196	—	236
Equity securities				
Domestic	313	109	—	422
International	112	238	—	350
Other				
Real estate	—	46	78	124
Private equity	—	—	64	64
Hedge funds and other alternative strategies	20	—	77	97
Total investments [2]	$ 508	$ 742	$ 219	$ 1,469
Liabilities				
Hedge funds and other alternative strategies	$ (11)	$ —	$ —	$ (11)
Total liabilities	$ (11)	$ —	$ —	$ (11)

(1) Amounts include investments in diversified fixed-income collective investment funds with exposure to mortgage-backed securities, government-issued securities, corporate debt, and other fixed-income securities.

(2) Amount excludes net receivables of $2 million for 2013 and $4 million for 2012, primarily related to Level 1 investments.

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

Investments in securities traded in active markets are measured based on quoted prices, which represent Level 1 inputs. Investments based on Level 2 inputs include direct investments in corporate debt and other fixed-income securities, as well as shares of open-end mutual funds or similar investment vehicles that do not have a readily determinable fair value, but are valued at the net asset value per share (NAV). For such funds, the NAV is the value at which investors transact with the fund, and is determined by the fund based on the estimated fair values of the underlying fund assets. Fair value of investments included as Level 3 inputs generally also reflect investments valued at fund NAVs, but, unlike investments characteristic of Level 2 fair-value measurements, such plan assets have significant liquidity restrictions or other features that are not reflected in NAV.

The following summarizes changes in the fair value of investments based on Level 3 inputs:

millions	Hedge Funds and Other Alternative Strategies	Private Equity	Real Estate	Total
Balance at January 1, 2012	$ 64	$ 55	$ 72	$ 191
Acquisitions (dispositions), net	9	4	2	15
Actual return on plan assets				
Relating to assets sold during the reporting period	(2)	2	—	—
Relating to assets still held at the reporting date	6	3	4	13
Balance at December 31, 2012	$ 77	$ 64	$ 78	$ 219
Acquisitions (dispositions), net	**(6)**	**—**	**2**	**(4)**
Actual return on plan assets				
Relating to assets sold during the reporting period	**1**	**4**	**—**	**5**
Relating to assets still held at the reporting date	**7**	**4**	**6**	**17**
Balance at December 31, 2013	**$ 79**	**$ 72**	**$ 86**	**$ 237**

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 value, 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.

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

Expected Benefit Payments

The following summarizes estimated benefit payments for the next ten years, including benefit increases due to continuing employee service:

millions	Pension Benefit Payments	Other Benefit Payments
2014	$ 139	$ 15
2015	148	16
2016	163	16
2017	185	17
2018	181	18
2019-2023	1,065	98

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 of $78 million for 2013, $55 million for 2012, and $41 million for 2011, related to these plans.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following summarizes quarterly financial data for 2013 and 2012:

millions except per-share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2013				
Sales revenues	**$ 3,718**	**$ 3,440**	**$ 3,789**	**$ 3,920**
Gains (losses) on divestitures and other, net	**175**	**57**	**64**	**(582)**
Algeria exceptional profits tax settlement	**33**	**—**	**—**	**—**
Deepwater Horizon settlement and related costs	**3**	**4**	**5**	**3**
Operating income (loss)	**1,289**	**1,140**	**689**	**215**
Tronox-related contingent loss	**—**	**—**	**—**	**850**
Net income (loss)	**484**	**959**	**223**	**(725)**
Net income (loss) attributable to noncontrolling interests	**24**	**30**	**41**	**45**
Net income (loss) attributable to common stockholders	**460**	**929**	**182**	**(770)**
Earnings per share:				
Net income (loss) attributable to common stockholders—basic	**$ 0.91**	**$ 1.84**	**$ 0.36**	**$ (1.53)**
Net income (loss) attributable to common stockholders—diluted	**$ 0.91**	**$ 1.83**	**$ 0.36**	**$ (1.53)**
Average number common shares outstanding—basic	**501**	**502**	**503**	**504**
Average number common shares outstanding—diluted	**503**	**504**	**505**	**504**
2012				
Sales revenues	$ 3,412	$ 3,200	$ 3,283	$ 3,412
Gains (losses) on divestitures and other, net	35	22	49	(2)
Algeria exceptional profits tax settlement	(1,804)	—	7	—
Deepwater Horizon settlement and related costs	8	3	4	3
Operating income (loss)	2,702	(279)	816	488
Tronox-related contingent loss	275	(525)	—	—
Net income (loss)	2,183	(70)	142	190
Net income attributable to noncontrolling interests	27	19	21	(13)
Net income (loss) attributable to common stockholders	2,156	(89)	121	203
Earnings per share:				
Net income (loss) attributable to common stockholders—basic	$ 4.30	$ (0.18)	$ 0.24	$ 0.40
Net income (loss) attributable to common stockholders—diluted	$ 4.28	$ (0.18)	$ 0.24	$ 0.40
Average number common shares outstanding—basic	499	500	500	500
Average number common shares outstanding—diluted	501	500	502	502

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 2013, 2012, and 2011 has been presented in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 932, *Extractive Activities—Oil and Gas* and the Securities and Exchange Commission's final rule, *Modernization of Oil and Gas Reporting*. Disclosures by geographic area include the United States and International. The International geographic area consists of proved reserves located in Algeria, Ghana, and China.

Oil and Gas Reserves

The following reserves disclosures reflect estimates of proved reserves, proved developed reserves, and proved undeveloped reserves, net of third-party royalty interests, of natural gas, oil, condensate, and natural-gas liquids (NGLs) owned at each year end and changes in proved reserves during each of the last three years. Natural-gas volumes are presented in billion cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch and volumes for oil, condensate, and NGLs are presented in millions of barrels (MMBbls). Total volumes are presented in millions of barrels of oil equivalent (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, prices, economic conditions, and governmental restrictions.

In 2013, Anadarko added 145 MMBOE of proved reserves through extensions and discoveries as the result of successful drilling primarily in the United States. Reserves revisions for 2013 include an increase of 370 MMBOE primarily related to successful infill drilling in large onshore areas, such as Wattenberg, Greater Natural Buttes, and the Eagleford shale, and a decrease of 23 MMBOE primarily due to lower ethane prices. Sales of proved reserves in place were 12 MMBOE, related to domestic assets. Acquisitions of proved reserves were 36 MMBOE, also related to domestic assets.

In 2012, Anadarko added 82 MMBOE of proved reserves through extensions and discoveries as the result of successful drilling in the United States. Reserves revisions for 2012 include an increase of 352 MMBOE primarily related to successful infill drilling in large onshore areas such as the Greater Natural Buttes, Wattenberg, and Carthage, and a decrease of 68 MMBOE associated with lower commodity prices. Sales of proved reserves in place were 81 MMBOE, related to onshore domestic assets.

In 2011, Anadarko added 174 MMBOE of proved reserves primarily as the result of successful drilling in the United States. Reserves revisions for 2011 include an increase of 210 MMBOE primarily related to successful infill drilling in large onshore areas, such as the Greater Natural Buttes, Wattenberg, and Pinedale fields, and an increase of 8 MMBOE primarily due to higher oil prices. Sales of proved reserves in place were 29 MMBOE, related to onshore domestic assets.

Prices used to compute the information presented in the following tables are adjusted only for fixed and determinable amounts under provisions in existing contracts. These prices, before adjustments, were \$3.67, \$2.76, and \$4.12 per MMBtu of natural gas and \$96.78, \$94.71, and \$96.19 per barrel of oil for 2013, 2012, and 2011.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Oil and Gas Reserves (Continued)

	Natural Gas (Bcf)			Oil and Condensate (MMBbls)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2010	8,117	—	8,117	498	251	749
Revisions of prior estimates	550	—	550	44	14	58
Extensions, discoveries, and other additions	614	—	614	52	—	52
Purchases in place	—	—	—	—	—	—
Sales in place	(64)	—	(64)	(10)	—	(10)
Production	(852)	—	(852)	(48)	(30)	(78)
December 31, 2011	8,365	—	8,365	536	235	771
Revisions of prior estimates	635	—	635	62	52	114
Extensions, discoveries, and other additions	418	—	418	9	—	9
Purchases in place	26	—	26	—	—	—
Sales in place	(199)	—	(199)	(42)	—	(42)
Production	(916)	—	(916)	(54)	(31)	(85)
December 31, 2012	**8,329**	**—**	**8,329**	**511**	**256**	**767**
Revisions of prior estimates	**1,276**	**—**	**1,276**	**96**	**21**	**117**
Extensions, discoveries, and other additions	**416**	**—**	**416**	**52**	**14**	**66**
Purchases in place	**153**	**—**	**153**	**1**	**—**	**1**
Sales in place	**(4)**	**—**	**(4)**	**(10)**	**—**	**(10)**
Production	**(965)**	**—**	**(965)**	**(58)**	**(32)**	**(90)**
December 31, 2013	**9,205**	**—**	**9,205**	**592**	**259**	**851**
Proved Developed Reserves						
December 31, 2010	5,982	—	5,982	303	150	453
December 31, 2011	6,113	—	6,113	352	173	525
December 31, 2012	6,445	—	6,445	318	208	526
December 31, 2013	**7,120**	**—**	**7,120**	**347**	**202**	**549**
Proved Undeveloped Reserves						
December 31, 2010	2,135	—	2,135	195	101	296
December 31, 2011	2,252	—	2,252	184	62	246
December 31, 2012	1,884	—	1,884	193	48	241
December 31, 2013	**2,085**	**—**	**2,085**	**245**	**57**	**302**

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, 2010	307	13	320	2,158	264	2,422
Revisions of prior estimates [1]	68	—	68	204	14	218
Extensions, discoveries, and other additions	20	—	20	174	—	174
Purchases in place	—	—	—	—	—	—
Sales in place	(8)	—	(8)	(29)	—	(29)
Production	(26)	—	(26)	(216)	(30)	(246)
December 31, 2011	361	13	374	2,291	248	2,539
Revisions of prior estimates [1]	65	(1)	64	233	51	284
Extensions, discoveries, and other additions	3	—	3	82	—	82
Purchases in place	—	—	—	4	—	4
Sales in place	(6)	—	(6)	(81)	—	(81)
Production	(30)	—	(30)	(237)	(31)	(268)
December 31, 2012	**393**	**12**	**405**	**2,292**	**268**	**2,560**
Revisions of prior estimates [1]	**17**	**—**	**17**	**326**	**21**	**347**
Extensions, discoveries, and other additions	**10**	**—**	**10**	**131**	**14**	**145**
Purchases in place	**9**	**—**	**9**	**36**	**—**	**36**
Sales in place	**(1)**	**—**	**(1)**	**(12)**	**—**	**(12)**
Production	**(33)**	**—**	**(33)**	**(252)**	**(32)**	**(284)**
December 31, 2013	**395**	**12**	**407**	**2,521**	**271**	**2,792**
Proved Developed Reserves						
December 31, 2010	222	—	222	1,523	150	1,673
December 31, 2011	267	—	267	1,638	173	1,811
December 31, 2012	283	—	283	1,675	208	1,883
December 31, 2013	**268**	**—**	**268**	**1,801**	**202**	**2,003**
Proved Undeveloped Reserves						
December 31, 2010	85	13	98	635	114	749
December 31, 2011	94	13	107	653	75	728
December 31, 2012	110	12	122	617	60	677
December 31, 2013	**127**	**12**	**139**	**720**	**69**	**789**

(1) Revisions of prior estimates include additions generated by Anadarko's infill drilling programs of 410 MMBOE for 2013, 383 MMBOE for 2012, and 203 MMBOE for 2011.

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 midstream and marketing reporting segments, liquefied natural gas (LNG) facilities costs, and other corporate activities are not included.

millions	United States	International	Total
December 31, 2013			
Capitalized			
Unproved properties	**$ 4,938**	**$ 1,970**	**$ 6,908**
Proved properties	**48,631**	**5,540**	**54,171**
	53,569	**7,510**	**61,079**
Less accumulated DD&A	**25,560**	**2,333**	**27,893**
Net capitalized costs	**$ 28,009**	**$ 5,177**	**$ 33,186**
December 31, 2012			
Capitalized			
Unproved properties	$ 5,188	$ 1,922	$ 7,110
Proved properties	43,016	4,969	47,985
	48,204	6,891	55,095
Less accumulated DD&A	21,206	1,950	23,156
Net capitalized costs	$ 26,998	$ 4,941	$ 31,939

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 asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligations 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 midstream and marketing reporting segments, LNG facilities costs, and other corporate activities are not included.

millions	United States	International	Total
Year Ended December 31, 2013			
Property acquisitions			
Unproved	**$ 282**	**$ 45**	**$ 327**
Proved	**324**	**—**	**324**
Exploration	**1,031**	**939**	**1,970**
Development	**4,421**	**444**	**4,865**
Total costs incurred	**$ 6,058**	**$ 1,428**	**$ 7,486**
Year Ended December 31, 2012			
Property acquisitions			
Unproved	$ 224	$ 15	$ 239
Proved	—	—	—
Exploration	1,064	1,000	2,064
Development	3,592	472	4,064
Total costs incurred	$ 4,880	$ 1,487	$ 6,367
Year Ended December 31, 2011			
Property acquisitions			
Unproved	$ 610	$ 37	$ 647
Proved	—	—	—
Exploration	666	803	1,469
Development	2,970	555	3,525
Total costs incurred	$ 4,246	$ 1,395	$ 5,641

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 oil and gas exploration and production reporting segment. Net revenues from production include only the revenues from the production and sale of natural gas, oil, condensate, and NGLs. Gains (losses) on property dispositions represent net gains or losses on sales of oil and gas properties. Production costs are those incurred to operate and maintain wells and related equipment and facilities used in oil and gas operations. Exploration expenses include dry hole costs, leasehold impairments, geological and geophysical expenses, and the costs of retaining unproved leaseholds. Algeria exceptional profits tax settlement represents the Company's resolution of the Algeria exceptional profits tax dispute with Sonatrach, which provided for the transfer of $1.7 billion of crude oil to the Company over a 12-month period ending in mid-2013. Deepwater Horizon settlement and related costs represents the Company's $4.0 billion settlement with BP, and associated legal and other costs, net of related insurance recoveries. Income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion, and amortization allowances, after giving effect to permanent differences. 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, 2013			
Net revenues from production			
Third-party sales	$ 6,567	$ 856	$ 7,423
Sales to consolidated affiliates	3,685	2,720	6,405
Gains (losses) on property dispositions	(618)	(3)	(621)
	9,634	3,573	13,207
Production costs			
Oil and gas operating	874	218	1,092
Oil and gas transportation and other	998	22	1,020
Production-related general and administrative expenses	332	5	337
Other taxes	569	455	1,024
	2,773	700	3,473
Exploration expenses	611	718	1,329
Depreciation, depletion, and amortization	3,222	399	3,621
Impairments related to oil and gas properties	704	—	704
Algeria exceptional profits tax settlement	—	33	33
Deepwater Horizon settlement and related costs	15	—	15
	2,309	1,723	4,032
Income tax expense	845	1,005	1,850
Results of operations	$ 1,464	$ 718	$ 2,182

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, 2012			
Net revenues from production			
Third-party sales	$ 6,233	$ 846	$ 7,079
Sales to consolidated affiliates	2,767	2,550	5,317
Gains (losses) on property dispositions	(16)	(48)	(64)
	8,984	3,348	12,332
Production costs			
Oil and gas operating	786	190	976
Oil and gas transportation and other	931	22	953
Production-related general and administrative expenses	318	18	336
Other taxes	581	599	1,180
	2,616	829	3,445
Exploration expenses	1,484	462	1,946
Depreciation, depletion, and amortization	3,320	390	3,710
Impairments related to oil and gas properties	364	—	364
Algeria exceptional profits tax settlement	—	(1,797)	(1,797)
Deepwater Horizon settlement and related costs	18	—	18
	1,182	3,464	4,646
Income tax expense	433	943	1,376
Results of operations	$ 749	$ 2,521	$ 3,270
Year Ended December 31, 2011			
Net revenues from production			
Third-party sales	$ 5,778	$ 2,051	$ 7,829
Sales to consolidated affiliates	3,652	1,353	5,005
Gains (losses) on property dispositions	(495)	454	(41)
	8,935	3,858	12,793
Production costs			
Oil and gas operating	862	131	993
Oil and gas transportation and other	867	23	890
Production-related general and administrative expenses	322	20	342
Other taxes	646	811	1,457
	2,697	985	3,682
Exploration expenses	688	388	1,076
Depreciation, depletion and amortization	3,193	391	3,584
Impairments related to oil and gas properties	1,225	—	1,225
Deepwater Horizon settlement and related costs	3,930	—	3,930
	(2,798)	2,094	(704)
Income tax expense	(1,015)	1,027	12
Results of operations	$ (1,783)	$ 1,067	$ (716)

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows

Estimates of future net cash flows from proved reserves of natural gas, oil, condensate, and NGLs for 2013, 2012, and 2011 are computed using the average first-day-of-the-month price during the 12-month period for the respective year. Prices used to compute the information presented in the tables below are adjusted only for fixed and determinable amounts under provisions in existing contracts. These prices, before adjustments, were $3.67, $2.76, and $4.12 per MMBtu of natural gas and $96.78, $94.71, and $96.19 per barrel of oil, for 2013, 2012, and 2011. 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 any known future changes, 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 U.S. Generally Accepted Accounting Principles.

The present value of future net cash flows is not an estimate of the fair value of Anadarko's proved reserves. 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.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

millions	United States	International	Total
December 31, 2013			
Future cash inflows	**$ 102,765**	**$ 28,454**	**$ 131,219**
Future production costs	**33,271**	**6,819**	**40,090**
Future development costs	**12,285**	**1,501**	**13,786**
Future income tax expenses	**20,222**	**8,148**	**28,370**
Future net cash flows	**36,987**	**11,986**	**48,973**
10% annual discount for estimated timing of cash flows	**15,818**	**4,049**	**19,867**
Standardized measure of discounted future net cash flows	**$ 21,169**	**$ 7,937**	**$ 29,106**
December 31, 2012			
Future cash inflows	$ 86,129	$ 29,268	$ 115,397
Future production costs	29,356	6,239	35,595
Future development costs	9,195	606	9,801
Future income tax expenses	16,804	9,035	25,839
Future net cash flows	30,774	13,388	44,162
10% annual discount for estimated timing of cash flows	13,236	4,612	17,848
Standardized measure of discounted future net cash flows	$ 17,538	$ 8,776	$ 26,314
December 31, 2011			
Future cash inflows	$ 98,615	$ 27,351	$ 125,966
Future production costs	30,385	8,342	38,727
Future development costs	10,534	995	11,529
Future income tax expenses	20,391	8,101	28,492
Future net cash flows	37,305	9,913	47,218
10% annual discount for estimated timing of cash flows	17,132	3,630	20,762
Standardized measure of discounted future net cash flows	$ 20,173	$ 6,283	$ 26,456

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
2013			
Balance at January 1	**$ 17,538**	**$ 8,776**	**$ 26,314**
Sales and transfers of oil and gas produced, net of production costs	**(7,478)**	**(2,881)**	**(10,359)**
Net changes in prices and production costs	**1,394**	**(1,072)**	**322**
Changes in estimated future development costs	**(2,326)**	**(193)**	**(2,519)**
Extensions, discoveries, additions, and improved recovery, less related costs	**2,659**	**(128)**	**2,531**
Development costs incurred during the period	**1,076**	**193**	**1,269**
Revisions of previous quantity estimates	**6,526**	**1,324**	**7,850**
Purchases of minerals in place	**253**	**—**	**253**
Sales of minerals in place	**284**	**—**	**284**
Accretion of discount	**2,671**	**1,465**	**4,136**
Net change in income taxes	**(1,865)**	**401**	**(1,464)**
Other	**437**	**52**	**489**
Balance at December 31	**$ 21,169**	**$ 7,937**	**$ 29,106**
2012			
Balance at January 1	$ 20,173	$ 6,283	$ 26,456
Sales and transfers of oil and gas produced, net of production costs	(6,384)	(2,571)	(8,955)
Net changes in prices and production costs	(7,948)	(391)	(8,339)
Changes in estimated future development costs	(744)	(70)	(814)
Extensions, discoveries, additions, and improved recovery, less related costs	963	—	963
Development costs incurred during the period	1,103	357	1,460
Revisions of previous quantity estimates	5,026	4,390	9,416
Purchases of minerals in place	(9)	—	(9)
Sales of minerals in place	(763)	—	(763)
Accretion of discount	3,063	1,139	4,202
Net change in income taxes	1,285	(759)	526
Other	1,773	398	2,171
Balance at December 31	$ 17,538	$ 8,776	$ 26,314

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
2011			
Balance at January 1	$ 16,987	$ 4,511	$ 21,498
Sales and transfers of oil and gas produced, net of production costs	(6,733)	(2,420)	(9,153)
Net changes in prices and production costs	2,424	4,777	7,201
Changes in estimated future development costs	32	(709)	(677)
Extensions, discoveries, additions, and improved recovery, less related costs	3,040	—	3,040
Development costs incurred during the period	561	442	1,003
Revisions of previous quantity estimates	5,438	313	5,751
Purchases of minerals in place	1	—	1
Sales of minerals in place	(560)	—	(560)
Accretion of discount	2,519	800	3,319
Net change in income taxes	(2,254)	(1,611)	(3,865)
Other	(1,282)	180	(1,102)
Balance at December 31	$ 20,173	$ 6,283	$ 26,456

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. 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 is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that the information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 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, 2013.

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 2013 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

See *Anadarko Board of Directors, Corporate Governance—Board of Directors, Corporate Governance—Committees of the Board* and *Section 16(a) Beneficial Ownership Reporting Compliance* in the Anadarko Petroleum Corporation Proxy Statement (Proxy Statement), for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 13, 2014 (to be filed with the Securities and Exchange Commission prior to April 3, 2014), 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/About/Pages/Governance.aspx. 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 2013, Compensation and Benefits Committee Report on 2013 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 Securities and Exchange Commission, 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, which are 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 report or incorporated by reference:

(1) The Consolidated Financial Statements of Anadarko Petroleum Corporation are listed on the Index to this report, page 87.

(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 as indicated.

Exhibit Number	Description	File Number
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	1-8968
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	1-8968
(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of May 15, 2012, filed as Exhibit 3.1 to Form 8-K filed on May 15, 2012	1-8968
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	1-8968
(ii)	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	1-8968
(iii)	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	1-8968
(iv)	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	1-8968
(v)	Form of 7.625% Senior Notes due 2014, filed as Exhibit 4.2 to Form 8-K filed on March 6, 2009	1-8968
(vi)	Form of 8.700% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on March 6, 2009	1-8968
(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	1-8968
(viii)	Form of 5.75% Senior Notes due 2014, filed as Exhibit 4.2 to Form 8-K filed on June 12, 2009	1-8968
(ix)	Form of 6.95% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on June 12, 2009	1-8968
(x)	Form of 7.95% Senior Notes due 2039, filed as Exhibit 4.4 to Form 8-K filed on June 12, 2009	1-8968

	Exhibit Number	Description	File Number
	4 (xi)	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	1-8968
	(xii)	Form of 6.200% Senior Notes due 2040, filed as Exhibit 4.2 to Form 8-K filed on March 16, 2010	1-8968
	(xiii)	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	1-8968
	(xiv)	Form of 6.375% Senior Notes due 2017, filed as Exhibit 4.2 to Form 8-K filed on August 12, 2010	1-8968
†	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	1-8968
†	(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	1-8968
†	(iii)	Anadarko Petroleum Corporation Amended and Restated 1999 Stock Incentive Plan, filed as Appendix A to DEF 14A filed on March 18, 2005	1-8968
†	(iv)	Form of Anadarko Petroleum Corporation Executive 1999 Stock Incentive Plan Stock Option Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 17, 2005	1-8968
†	(v)	Form of Anadarko Petroleum Corporation Non-Executive 1999 Stock Incentive Plan Stock Option Agreement, filed as Exhibit 10.3 to Form 8-K filed on November 17, 2005	1-8968
†	(vi)	Form of Stock Option Agreement—1999 Stock Incentive Plan (UK Nationals), filed as Exhibit 10.4 to Form 8-K filed on November 17, 2005	1-8968
†	(vii)	Amendment to Stock Option Agreement Under the Anadarko Petroleum Corporation 1999 Stock Incentive Plan, filed as Exhibit 10.1 to Form 8-K filed on January 23, 2007	1-8968
†	(viii)	Anadarko Petroleum Corporation 1999 Stock Incentive Plan (Amendment to Performance Unit Agreement), filed as Exhibit 10.3 to Form 8-K filed on November 13, 2007	1-8968
†	(ix)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Agreement, filed as Exhibit 10(b)(xxiv) to Form 10-K for year ended December 31, 1999, filed on March 16, 2000	1-8968
†	(x)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Unit Award Letter, filed as Exhibit 10.1 to Form 8-K filed on November 13, 2007	1-8968
†	(xi)	The Approved UK Sub-Plan of the Anadarko Petroleum Corporation 1999 Stock Incentive Plan, filed as Exhibit 10(b)(xxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004	1-8968
†	(xii)	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	1-8968
†	(xiii)	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	1-8968
†	(xiv)	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	1-8968

	Exhibit Number	Description	File Number
†	10 (xv)	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	1-8968
†	(xvi)	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	1-8968
†	(xvii)	Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10(xxii) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010	1-8968
†	(xviii)	Anadarko Retirement Restoration Plan (As Amended and Restated Effective as of November 7, 2007), filed as Exhibit 10.2 to Form 8-K filed on November 13, 2007	1-8968
†	(xix)	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	1-8968
†	(xx)	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	1-8968
†	(xxi)	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	1-8968
†	(xxii)	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	1-8968
†	(xxiii)	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	1-8968
†	(xxiv)	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	1-8968
†	(xxv)	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	1-8968
†	(xxvi)	Form of Termination Agreement and Release of All Claims Under Officer Severance Plan, filed as Exhibit 10(b)(v) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003	1-8968
†	(xxvii)	Form of Director and Officer Indemnification Agreement, filed as Exhibit 10 to Form 8-K filed on September 3, 2004	1-8968
	(xxviii)	$5,000,000,000 Revolving Credit Agreement, dated as of September 2, 2010, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., DnB NorBank ASA, The Royal Bank of Scotland plc, Société Général, and Wells Fargo Bank, N.A., as Syndication Agents, and the several lenders named therein, filed as Exhibit 10.1 to Form 8-K filed on September 8, 2010	1-8968
	(xxix)	First Amendment to Revolving Credit Agreement, dated as of August 3, 2011, to the Revolving Credit Agreement dated as of September 2, 2010, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A. as Administrative Agent, Bank of America, N.A., DnB Nor Bank ASA, The Royal Bank of Scotland plc, Société Générale, and Wells Fargo Bank, N.A., as co-syndication agents, and each of the Lenders from time to time party thereto, filed as Exhibit 10(i) to Form 10-Q for quarter ended September 30, 2011, filed on October 31, 2011	1-8968

	Exhibit Number	Description	File Number
†	10 (xxx)	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	1-8968
†	(xxxi)	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	1-8968
†	(xxxii)	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	1-8968
†	(xxxiii)	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	1-8968
†	(xxxiv)	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	1-8968
†	(xxxv)	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	1-8968
†	(xxxvi)	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	1-8968
†	(xxxvii)	Anadarko Petroleum Corporation Benefits Trust Agreement, amended and restated effective as of November 5, 2008, filed as Exhibit 10(lvi) to Form 10-K for year ended December 31, 2008, filed on February 25, 2009	1-8968
†	(xxxviii)	Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2010), filed as Exhibit 10(xlvi) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010	1-8968
†	(xxxvix)	Amended and Restated Employment Agreement between James T. Hackett and Anadarko Petroleum Corporation, dated November 11, 2009, filed as Exhibit 10.4 to Form 8-K filed on November 13, 2009	1-8968
	(xl)	Letter Agreement between James T. Hackett and Anadarko Petroleum Corporation, dated February 16, 2012, filed as Exhibit 10.1 to Form 8-K filed on February 21, 2012	1-8968
†	(xli)	Operating Agreement, dated October 1, 2009, between BP Exploration & Production Inc., as Operator, and MOEX Offshore 2007 LLC, as Non-Operator, as ratified by that certain Ratification and Joinder of Operating Agreement, dated December 17, 2009, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation (as Non-Operator), Anadarko E&P Company LP (as predecessor in interest to Anadarko Petroleum Corporation), and MOEX Offshore 2007 LLC, together with material exhibits, filed as Exhibit 10 to Form 10-Q for quarter ended June 30, 2010, filed on August 3, 2010	1-8968
†	(xlii)	Confidential Settlement Agreement, Mutual Releases and Agreement to Indemnify, dated October 16, 2011, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation, Anadarko E&P Company LP, BP Corporation North America Inc. and BP p.l.c., filed as Exhibit 10(xlii) to Form 10-K for year ended December 31, 2011, filed on February 21, 2012	1-8968
†	(xliii)	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	1-8968
†	(xliv)	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	1-8968

	Exhibit Number		Description	File Number
†	10	(xlv)	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	1-8968
†		(xlvi)	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	1-8968
†		(xlvii)	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	1-8968
†		(xlviii)	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	1-8968
†		(xlix)	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	1-8968
†		(l)	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	1-8968
†		(li)	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	1-8968
†		(lii)	Amended and Restated Performance Unit Award Agreement, effective November 5, 2012, for Mr. R. A. Walker, filed as Exhibit 10.3 to Form 8-K filed on November 9, 2012	1-8968
*	12		Computation of Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Stock Dividends	
*	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.	

Exhibit Number	Description	File Number
* 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.

‡ Application has been made to the Securities and Exchange Commission (SEC) for confidential treatment of certain provisions of the exhibit. Omitted material for which confidential treatment has been requested has been filed separately with the SEC.

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.

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 28, 2014 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 28, 2014.

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/ M. CATHY DOUGLAS M. Cathy Douglas	Senior Vice President, Chief Accounting Officer and Controller

(iv) Directors:*

ANTHONY R. CHASE
KEVIN P. CHILTON
H. PAULETT EBERHART
PETER J. FLUOR
RICHARD L. GEORGE
PRESTON M. GEREN III
CHARLES W. GOODYEAR
JOHN R. GORDON
ERIC D. MULLINS
PAULA ROSPUT REYNOLDS

* Signed on behalf of each of these persons and on his own behalf:

By: /s/ ROBERT G. GWIN

Robert G. Gwin, Attorney-in-Fact