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2010 ANNUAL REPORT

ANADARKO PETROLEUM CORPORATION

To Our Shareholders:

Anadarko delivered strong operating performance in 2010 and continued to generate competitive returns, and advance our longer-term growth objectives.

We reported record sales volumes of 235 million barrels of oil equivalent (BOE) in 2010, representing an approximate 7-percent year-over-year increase for the second consecutive year. Additionally, we added 359 million BOE of proved reserves, replacing over 153-percent of our production with better than targeted reserve-replacement costs. We achieved record drilling cycle times across our major onshore operating areas during the year, and our ongoing efforts to reduce lease operating expenses (LOE) per BOE yielded good results again in 2010, with a 9-percent year-over-year reduction.

A significant portion of our record sales volumes and reserve growth resulted from accelerated activity in our U.S. onshore shale plays, where we have established a net risked resource potential of approximately 1.5 billion BOE from just these play types. Increased production from the Eagleford Shale, and other resource plays with higher liquids yields such as Wattenberg, Bone Spring and Greater Natural Buttes, generated very attractive margins and contributed to an overall increase in liquids sales volumes of 13 percent relative to 2009. A $1.5 billion joint-venture program, coupled with infrastructure expansions and strategic service agreements, enabled Anadarko to achieve substantial growth in the Marcellus Shale play with an exit rate of approximately 330 million gross cubic feet per day. The Marcellus was the only major area where we continued to drill solely for dry natural gas, due to the proximity to premium markets that further enhance the already robust economics of the play.

Just prior to year end, we achieved the delivery of first oil from the Jubilee field offshore Ghana, in record time for a project of this nature. We expect Jubilee to serve as a foundation to build upon in West Africa, given our additional exploration success and sizable opportunities in the region. Opportunities to expand our activities also exist in Mozambique, where we announced three of the largest discoveries in all of Africa during 2010 with the Windjammer, Barquentine and Lagosta wells. Based on the expected resource potential of these natural gas discoveries, we are moving forward with an appraisal program and evaluating LNG commercialization options. In total, the exploration team was successful on about 60 percent of our offshore wells in 2010 with discoveries in Brazil, Ghana, Indonesia, Mozambique, Sierra Leone and the United States. We also achieved a 100-percent success rate in our 2010 appraisal program, which included four successful appraisal and/or sidetrack wells in the Gulf of Mexico, prior to the government-mandated moratorium.

The tragic *Deepwater Horizon* event in April 2010, and the regulatory uncertainty that followed, created challenges for many deepwater operators. It also demonstrated the depth and flexibility of our portfolio, as we effectively reallocated capital, strengthened our balance sheet and enhanced liquidity in a manner that enabled us to exceed our corporate operating objectives for the year. Importantly, this event continues to serve as a vivid reminder of the significance of safety and environmental stewardship in our business. We remain committed to working with all stakeholders to ensure our operations are conducted in a manner that protects life, land, water and air. Consistent with this commitment, we earned our second Utah Earth Day Award, achieved an additional LEED® Certification for our corporate headquarters facilities in The Woodlands and were instrumental in helping the Ground Water Protection Council create a voluntary, state-based system for disclosing the contents of hydraulic fracturing fluids through a public registry. Also of note, Anadarko was named Houston's Top Workplace and received special recognition for our corporate ethics from the *Houston Chronicle*.

We have often stated that the talent and skills of our employees are key to our success – certainly this was the case again in 2010, as their efforts and achievements helped bring about a strong recovery in our share price. We thank them for their commitment and hard work and we thank you, our shareholders, for your support during 2010 and for recognizing the embedded value in Anadarko. We look forward to continuing to build upon the record results of 2010, both this year and well into the future.

Warm regards,

James T. Hackett

James T. Hackett
Chairman and Chief Executive Officer

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, 2010

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 Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ 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 30, 2010, was $17.8 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, 2011, is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	496,258,104

Part of Form 10-K	Documents Incorporated By Reference
Part III	Portions of the Proxy Statement for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 17, 2011 (to be filed with the Securities and Exchange Commission prior to April 1, 2011).

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PART I

Items 1 and 2. Business and Properties

GENERAL

Anadarko Petroleum Corporation is among the world's largest independent oil and natural-gas exploration and production companies, with 2.4 billion barrels of oil equivalent (BOE) of proved reserves at December 31, 2010. Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural-gas resources vital to the world's health and welfare. Anadarko's portfolio of assets includes positions in onshore resource plays in the Rocky Mountains region, the southern United States and the Appalachian basin. The Company is also among the largest producers in Algeria and in the deepwater Gulf of Mexico, and has significantly expanded its deepwater opportunities worldwide to include positions in high-potential basins located offshore Brazil, East and West Africa, China, Indonesia and New Zealand.

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

Anadarko's primary business segments are managed separately due to the nature of the products and services, the unique technology, and distribution and marketing requirements. The Company's three operating 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).
Midstream—This segment provides gathering, processing, treating and transportation services to Anadarko and third-party oil and natural-gas producers. The Company owns and operates natural-gas gathering, processing, treating and transportation systems in the United States.
Marketing—This segment sells much of Anadarko's production, as well as production purchased from third parties. The Company actively markets oil, natural gas and NGLs in the United States, and actively markets oil from Algeria, China and Ghana.

The Company owns interests in several coal, trona (natural soda ash) and industrial mineral properties through non-operated joint ventures and royalty arrangements within and adjacent to its land grant acreage position (Land Grant). The Land Grant, the ownership of which is a significant competitive advantage for Anadarko, consists of land granted to the Company by the federal government in the mid-1800s that passes through Colorado and Wyoming and into Utah. Within the Land Grant, the Company has fee ownership of the mineral rights under approximately 8 million acres.

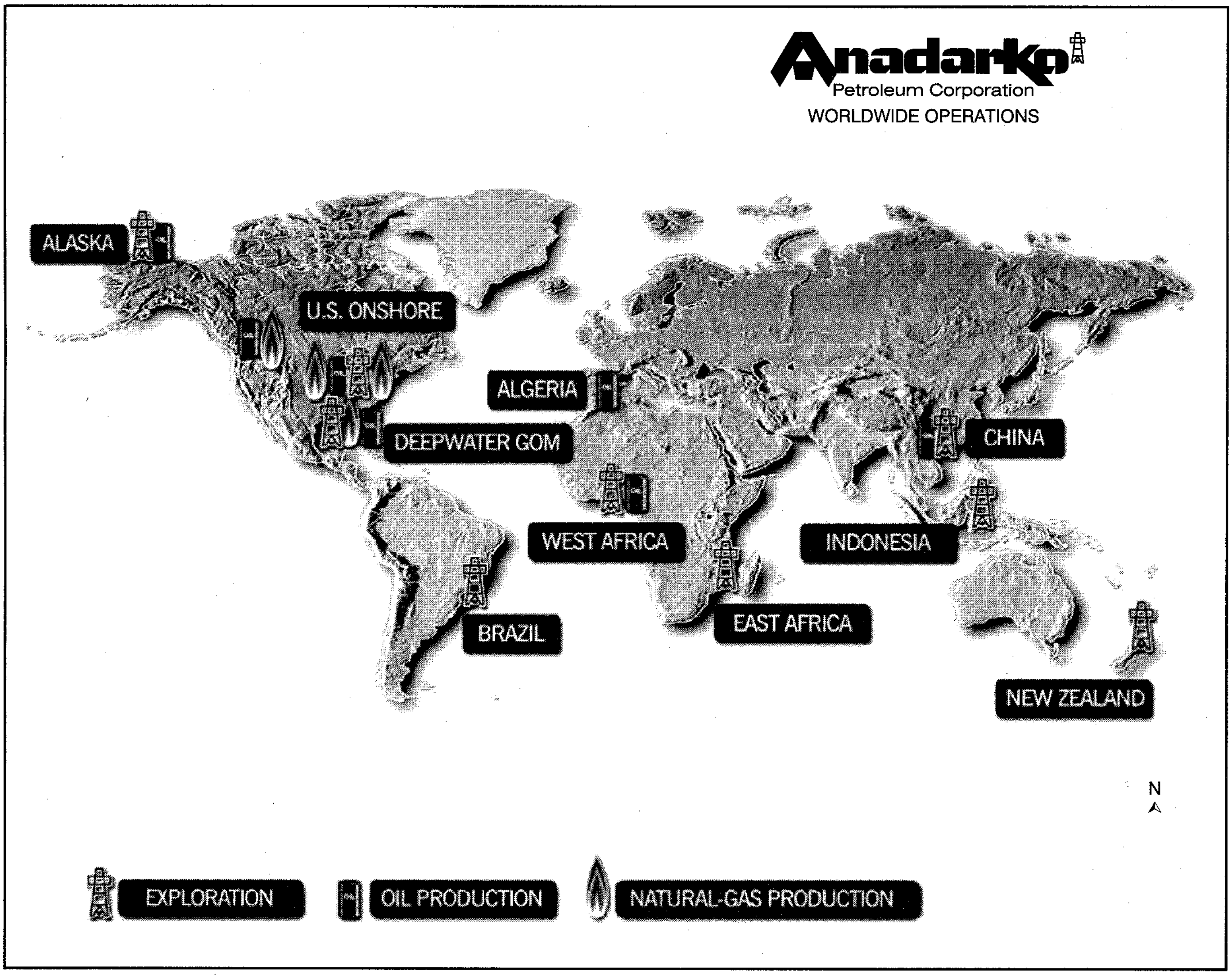
Unless the context otherwise requires, the terms "Anadarko" or "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company's corporate headquarters is located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046, and its telephone number is (832) 636-1000. Additionally, unless noted otherwise, the following information relates to Anadarko's continuing operations and excludes the discontinued Canadian operations. For additional information, see *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

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 items 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 Internet site located at www.anadarko.com/Investor/Pages/SECFilings.aspx. The Company will also make available to any stockholder, without charge, 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 Department, P.O. Box 1330, Houston, Texas 77251-1330 or call (832) 636-1216.

In addition, 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. The Company plans to allocate approximately 85% of its 2011 capital budget to the oil and gas exploration and production segment.



United States

Overview Anadarko's operations in the United States include oil and natural-gas exploration and production onshore in the Lower 48 states and Alaska, and the deepwater Gulf of Mexico. The Company's operations in the United States accounted for 89% of both Anadarko's total sales volumes during 2010 and total proved reserves at year-end 2010. During 2010, the Company participated in the drilling of 1,570 natural-gas wells, 236 oil wells and 10 dry holes in the United States. The Company plans to allocate approximately 75% of its 2011 oil and gas exploration and production segment capital budget to United States properties.

Onshore The Company plans to allocate approximately 60% of its 2011 oil and gas exploration and production segment capital budget to onshore properties.

Rocky Mountains Region Anadarko's Rocky Mountains Region (Rockies) properties are located in Colorado, Utah and Wyoming and are a mix of oil and natural-gas plays. Although the current mix is more heavily weighted toward natural gas, the Company has redirected its capital investment plans to target development in areas that offer higher liquids yields (liquids-rich areas). Anadarko operates approximately 13,500 wells and has an interest in approximately 10,100 non-operated wells in the Rockies. Anadarko operates tight gas and coalbed methane (CBM) natural-gas assets, as well as enhanced oil recovery (EOR) projects within the region. The Company also earns royalty revenue from many non-operated wells located within the Land Grant. Activities in the Rockies focus on expanding the potential of existing fields to increase production and adding proved reserves through infill drilling and down-spacing operations, re-completions and re-fracture stimulations of existing wells. In 2010, the Company drilled 1,121 wells in the Rockies and plans to maintain an active drilling program in the region in 2011, with a continued emphasis on liquids-rich areas.

The Company's tight-gas assets are located in the Greater Natural Buttes area in eastern Utah, the Wattenberg field in northeast Colorado, and the Greater Green River area in Wyoming. Anadarko operates 7,500 wells and has an interest in 4,700 non-operated wells in these tight gas areas. Anadarko uses fracture-stimulation technology to produce from tight gas formations. The Company also benefits from third-party-operator success in the Wyoming portion of the Land Grant and actively pursues farm-out projects to capture incremental royalty revenue from exploration and development activity in the area.

The Greater Natural Buttes field, where the Company operates over 1,900 wells, is a core asset for the Company. In 2010, production volumes from the field increased by 10% over 2009 volumes. The Company drilled 263 wells during the year, while reducing the cost per foot drilled by 16%. Based on efficiency gains within the drilling program and a slightly higher rig count, Anadarko was able to drill 70% more wells than were drilled in 2009, while decreasing capital spending per well. The Company has identified more than 6,000 potential locations in the Greater Natural Buttes field for future development. Many of these locations are infill drilling opportunities focused on down-spacing from 40-acre well density to 10-acre well density. Another core area for the Company is the Wattenberg field, where Anadarko operates over 4,800 wells. During 2010, the Company drilled 363 wells in the Wattenberg field and increased sales volumes 11% compared to 2009. Liquids sales volumes in the field increased 20% during the year as the Company focused its efforts on liquids-rich areas. During 2010, 1,777 fracture stimulation treatments were performed compared to 1,010 in 2009. In 2011, Anadarko plans to maintain an active drilling program in these tight gas areas with a focus on liquids-rich areas.

Anadarko also operates multiple CBM properties in the Rockies. 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. Anadarko's primary CBM properties are located in the Powder River basin and Atlantic Rim areas in Wyoming and the Helper and Clawson fields in Utah. Anadarko operates approximately 4,600 low-cost CBM wells and has an interest in approximately 5,200 non-operated CBM wells in the Rockies. In 2011, Anadarko expects to reduce activity levels in its CBM development program as the Company continues to allocate its capital spending toward its liquids-rich opportunities.

The Company's EOR operations increase the amount of oil that can be produced from mature reservoirs after primary recovery methods have been completed. During 2010, the Company continued to pursue development of its Rockies EOR assets at the Monell and Salt Creek fields in Wyoming. Monell field development is now largely complete with only minor infrastructure investments planned for 2011 to enhance carbon dioxide flood operations. Throughout 2011, the Company plans to progress the long-term tertiary recovery operations at Salt Creek which the Company has been continuously implementing since 2003.

Southern and Appalachia Region Anadarko's Southern and Appalachia Region properties are primarily located in Texas and Pennsylvania. Operations in these areas are focused on finding and developing both natural gas and liquids from shales, tight sands and fractured-reservoir plays.

Anadarko holds interest in approximately 840,000 net fairway acres in shale and other emerging-growth plays throughout the Southern and Appalachia Region. These plays include the Eagleford/Pearsall plays in southwest Texas, the Marcellus shale in north-central Pennsylvania, the Bone Spring and Avalon plays in West Texas and the Haynesville shale in East Texas and western Louisiana. Anadarko also has tight gas and/or fractured-reservoir operations in the Bossier, Haley, Carthage, Chalk, South Texas and Ozona areas in Texas, and the Hugoton area in southern Kansas.

The Company drilled 479 wells and completed 359 wells in the Southern and Appalachia Region during 2010. Year-over-year drilling practices have changed significantly within the region with approximately 93% of the rig fleet drilling horizontally in 2010. Drilling efficiency improved in every area with respect to cycle times, while also drilling longer lateral lengths. As natural-gas prices declined during the year, the Company redirected drilling rig activity from gas-prone areas to liquids-rich areas, such as the Eagleford shale in the Maverick basin and the Bone Spring formation in the Delaware basin.

In the first quarter of 2010, Anadarko purchased additional acreage in the Maverick basin, where the liquids-rich Eagleford shale play is being developed. Anadarko currently holds approximately 405,000 gross and 288,000 net acres with an average working interest of approximately 71% in this area. During 2010, rig activity increased from two rigs at the beginning of the year to seven rigs at year end, which helped to increase net production from 2,400 barrels of oil equivalent per day (BOE/d) to over 14,000 BOE/d. Anadarko realized drilling efficiencies in the Eagleford shale play this year, where spud-to-release times were reduced to less than 12 days at the end of 2010, compared to more than 22 days in mid-2009. In 2010, 104 wells were spud and 71 wells were completed. With infrastructure and service agreements in place, about 94% of all completed wells are flowing to sales. Exploration in the area is focused on appraising and delineating the Pearsall shale formation. During the year, three Pearsall wells were spud and four wells were completed. Additional delineation of the Pearsall shale formation is planned for 2011.

In the Appalachian basin, where the Marcellus shale play is being actively developed, the Company entered into a joint-venture agreement that permits a third party to participate with the Company as a 32.5% partner in the Company's Marcellus shale assets. The third party may earn 100,000 net acres in exchange for funding 100% of the Company's share of 2010 development costs and 90% of these costs thereafter, up to approximately $1.4 billion, with an estimated funding-completion date in late 2012. During 2010, 53 operated horizontal wells were spud and 22 wells were completed. Anadarko also participated in 158 new horizontal wells and 110 completions as a non-operating partner in the area. Gross production increased from 40 million cubic feet per day (MMcf/d) in January 2010 to a year-end exit rate of approximately 330 MMcf/d. During 2010, gross delivery capacity increased to 1.2 billion cubic feet per day (Bcf/d). The Company plans to increase operated activity in this area in 2011.

The Bone Spring formation in the Delaware basin is an emerging liquids-rich reservoir. Anadarko currently holds 145,000 net acres in a joint-venture with an average working interest of approximately 44%. In 2010, 41 wells were spud and 29 wells were completed in Bone Spring. Drilling and well performance continue to improve in this area with recent well tests in excess of 1,500 BOE/d. Exploration in the Delaware basin is also focused on appraising the liquids-rich Avalon shale formation. At December 31, 2010, five operated rigs and three non-operated rigs were active in the Delaware basin and the Company plans to increase activity in 2011.

Alaska Anadarko's oil and natural-gas production and development activity in Alaska is concentrated primarily on the North Slope. Development activity continued at the Colville River Unit through 2010 with 11 wells drilled. In 2011, the Company anticipates participating in approximately 14 development wells and sanctioning of the Alpine West satellite development.

Gulf of Mexico In the Gulf of Mexico, Anadarko owns an average 63% working interest in 505 blocks. The Company operates seven active floating platforms, holds interests in 26 producing fields and is in the process of delineating and developing five additional fields in the area. Anadarko plans to allocate approximately 15% of its 2011 oil and gas exploration and production segment capital budget to the deepwater Gulf of Mexico with the understanding that the regulatory environment continues to progress.

In April 2010, the Macondo well in the Gulf of Mexico, in which Anadarko holds a 25% non-operating leasehold interest, discovered hydrocarbon accumulations. During suspension operations, the well blew out, an explosion occurred on the *Deepwater Horizon* drilling rig, and the drilling rig sank, resulting in the release of hydrocarbons into the Gulf of Mexico. The Macondo well was permanently plugged on September 19, 2010, when BP Exploration & Production Inc. (BP), the operator and 65% owner of the Macondo lease, completed a "bottom kill" cementing operation in connection with the successful interception of the well by a relief well. Investigations by the federal government and other parties into the cause of the well blowout, explosion, and resulting oil spill, as well as other matters arising from or relating to these events, are ongoing. For additional information see *Note 2—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, *Risk Factors* under Item 1A of this Form 10-K and *Legal Proceedings* under Item 3 of this Form 10-K.

In May and July 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), previously known as the Minerals Management Service, an agency of the Department of the Interior (DOI), issued directives requiring lessees and operators of federal oil and gas leases in the Outer Continental Shelf regions of the Gulf of Mexico and Pacific Ocean to cease drilling all new deepwater wells, including wellbore sidetracks and bypasses, through November 30, 2010. These deepwater drilling moratoria (collectively, the Moratorium) prohibited drilling and/or spudding any new wells, and required operators that were in the process of drilling wells to proceed to the next safe opportunity to secure such wells, and to take all necessary steps to cease operations and temporarily abandon the impacted wells. Anadarko ceased all drilling operations in the Gulf of Mexico in accordance with the Moratorium, which resulted in the suspension of operations of two operated deepwater wells (Lucius and Nansen) and one non-operated deepwater well (Vito). The Moratorium was lifted October 12, 2010, but the BOEMRE has not approved new drilling permits. The new safety and environmental laws and regulations required by the DOI, delays in the processing and approval of drilling permits and any additional actions could adversely affect and further delay new drilling and ongoing development efforts in the Gulf of Mexico. For additional information see *Risk Factors* under Item 1A of this Form 10-K.

The Company is ready to resume drilling in the Gulf of Mexico in 2011, as soon as permits are approved. Anadarko's Gulf of Mexico exploration program is expected to focus on the deep waters of the extensive middle-to-lower Miocene play in the central Gulf of Mexico, the Lower Tertiary play in the western Gulf of Mexico and the developing Pliocene play in the central Gulf of Mexico. During 2010, Anadarko participated in four successful deepwater wells (two Lucius appraisal wells and two Vito appraisal wells) and encountered mechanical problems on the Heidelberg appraisal well, which was being prepared to re-spud when the Moratorium was imposed.

Anadarko utilizes a hub-and-spoke infrastructure in the Gulf of Mexico in order to develop resources more quickly and at a substantial cost savings. In 2010, Anadarko drilled five development wells in the Gulf of Mexico before the Moratorium, and continued to make progress on the Caesar Tonga development project. The Company received permits to initiate well completions and is currently completing the first two Caesar Tonga wells; however, a recent mechanical issue involving the production riser system will delay first production, which was expected in mid-2011. As operator of the Caesar Tonga development project, the Company directed that the production riser undergo an extensive qualification program prior to installation. Additionally, in its role as operator, the Company pursued hydro-testing of the riser, the recent results of which have led Anadarko to delay startup in the interest of safety and the environment. Completion activities will continue as Anadarko works with the co-owners to secure a reliable alternative for the production riser. This field is a sub-sea tieback to the Anadarko-operated and owned Constitution spar, where required topside construction, modification and installation began on the Constitution spar in 2009.

International

Overview The Company's international oil and natural-gas production and development operations are located primarily in Algeria, China and Ghana. The Company also has exploration acreage in Ghana, Brazil, Indonesia, Mozambique, Sierra Leone, Cote d'Ivoire, Liberia, New Zealand, Kenya and other countries. These international locations accounted for 11% of both Anadarko's total sales volumes during 2010 and total proved reserves at year-end 2010. Anadarko drilled 45 wells in international areas in 2010 and achieved first oil at the Jubilee field offshore Ghana in 3.5 years from discovery. In 2011, the Company expects to drill approximately 42 development and 20 exploration wells at various international locations. Anadarko plans to allocate approximately 25% of its 2011 oil and gas exploration and production segment capital budget to international areas.

Algeria Anadarko is engaged in development and production activities in Algeria's Sahara Desert in Blocks 404 and 208. Currently, all production is from fields located in Block 404, which produce through the Hassi Berkine South and Ourhoud Central Production Facilities (CPF). Construction of the El Merk CPF and associated infrastructure for the development in Block 208 is progressing and the overall project was approximately 65% complete at December 31, 2010. Initial production is expected to occur around the beginning of 2012 and will be increased gradually until provisional acceptance (or alternatively until commission) of the full facility, which is expected to occur in late 2012. During 2010, nine development wells were drilled in Blocks 404 and 208. The Company expects 2011 development drilling activity to be similar to 2010 levels, with a focus on El Merk drilling.

Contracts and Partners Since October 1989, the Company's operations in Algeria have been governed by a Production Sharing Agreement (PSA) between Anadarko, two third parties, and Sonatrach, the national oil and gas company of Algeria. Anadarko's interest in the PSA for Blocks 404 and 208 is 50% before participation at the exploitation stage by Sonatrach. The Company has two partners, each with a 25% interest, also prior to participation by Sonatrach. Under the terms of the PSA, oil reserves that are discovered, developed and produced are shared by Sonatrach, Anadarko and the remaining two partners. Sonatrach is responsible for 51% of the development and production costs, Anadarko is responsible for 24.5% and its two partners are responsible for 12.25% each. Anadarko and its partners have completed the exploration program on Blocks 404 and 208 and now participate only in development activity on these blocks. Anadarko and its joint-venture partners funded Sonatrach's share of exploration costs and are entitled to recover these exploration costs from production during the development phase.

In March 2006, Anadarko received a letter from Sonatrach purporting to give notice under the PSA that the enactment of a 2005 law (2005 Law), relating to hydrocarbons, triggered Sonatrach's right under the PSA to renegotiate the PSA in order to re-establish equilibrium of Anadarko's and Sonatrach's interests. Anadarko and Sonatrach reached an impasse over whether Sonatrach had a right to renegotiate the PSA based on the 2005 Law and entered into a formal non-binding conciliation process under the terms of the PSA in an attempt to resolve this dispute. The conciliation on the 2005 Law dispute was concluded in 2007 without a definitive resolution. There have been no further developments on the 2005 Law dispute since 2007. Anadarko currently is unable to reasonably estimate the economic impact under the PSA, if Sonatrach were to succeed in modifying the PSA.

Exceptional Profits Tax In July 2006, the Algerian parliament approved legislation establishing an exceptional profits tax on foreign companies' Algerian oil production. In December 2006, implementing regulations regarding this legislation were issued. These regulations provide for an exceptional profits tax imposed on gross production at rates of taxation ranging from 5% to 50% based on average daily production volumes for each calendar month in which the price of Brent crude averages over $30 per barrel. Exceptional profits tax applies to the full value of production rather than to the amount in excess of $30 per barrel.

In response to the Algerian government's imposition of the exceptional profits tax, the Company notified Sonatrach of its disagreement with the collection of the exceptional profits tax. The Company believes that the PSA provides fiscal stability through several provisions that require Sonatrach to pay all taxes and royalties. To facilitate discussions between the parties in an effort to resolve the dispute, in October 2007, the Company initiated a conciliation proceeding on the exceptional profits tax as provided in the PSA. Any recommendation issued by a conciliation board (Conciliation Board) arising out of the conciliation proceeding is non-binding on the parties. The Conciliation Board issued its non-binding recommendation in November 2008. In February 2009, the Company initiated arbitration against Sonatrach with regard to the exceptional profits tax. In conformance with the terms of the PSA, a notice of arbitration was submitted to Sonatrach. The arbitration hearing on the merits of the claims presented by Anadarko is scheduled for June 2011.

China Anadarko's development and production activities in China are located offshore in Bohai Bay. Development drilling and recompletion activity was ongoing throughout 2010, and Anadarko drilled 24 wells during the year. In addition, during 2010, a facility expansion was approved and an infill drilling program was implemented in order to sustain current-level production. Development drilling activity is expected to decrease in 2011, as the Company plans to participate in drilling one deepwater exploration well in the South China Sea during 2011.

Ghana Anadarko's exploration and development activities in Ghana are located offshore in the West Cape Three Points block and the Deepwater Tano block. During 2010, the Company and its partners took delivery and completed installation and commissioning of a floating production, storage and offloading vessel (FPSO) at the Jubilee field. In December 2010, the Company and its partners achieved first oil from the Jubilee field, on budget and in 3.5 years following discovery. Additional development phases tied back to the FPSO may be executed based on performance data from wells already drilled. Immediately following first oil, well capacity was approximately 45,000 BOE/d and is expected to increase to 120,000 BOE/d over a three- to six-month period as additional wells are brought on-line. The Company and its partners have drilled 16 wells in the Jubilee field as of December 31, 2010, with most of the 2010 work focused on completing previously drilled wells. One additional Phase 1 well remains to be drilled during 2011. The Company and its partners filed a declaration of commerciality on the Mahogany East field during 2010 and anticipate sanctioning of the plan of development by year-end 2011. During 2010, the Company also participated in six exploration and appraisal wells outside the Jubilee field, including the successful Mahogany #5 appraisal well, the initial Enyenra (formerly Owo) discovery and subsequent sidetrack, and two appraisal wells at Tweneboa. The Tweneboa #3 appraisal well and the Teak exploration well were drilling at December 31, 2010. In early 2011, the Tweneboa #3 appraisal well and the Teak exploration well were completed and determined to be successful. In 2011, the Company plans to participate in seven to nine exploration and appraisal wells in Ghana.

Brazil Anadarko holds exploration interests in seven blocks located offshore Brazil in the Campos and Espírito Santo basins. In these areas, Anadarko drilled two exploration wells in 2010, including the Itauna discovery in late 2010 on block BM-C-29. Also during 2010, Anadarko completed a successful pre-salt drill stem test on the Wahoo #1 well on block BM-C-30 in the deepwater Campos basin. In 2011, Anadarko expects to participate in two to three exploration and appraisal wells.

Indonesia Anadarko has participating interests in approximately 4.5 million exploration acres in Indonesia through a combination of several operated and non-operated Production Sharing Contracts (PSC). The Company participated in three exploration wells in 2010, including the successful Badik #1 well in the Tarakan basin under the Nunukan PSC. The Company may participate in one exploration or appraisal well in 2011.

Mozambique The Company has participating interests in two blocks (one onshore and one offshore) totaling approximately 6.4 million acres. In 2010, Anadarko primarily focused on deepwater opportunities in the Offshore Area 1 of the Rovuma basin where the Company holds a 36.5% working interest. During the year, Anadarko announced three natural-gas discoveries at the Windjammer, Barquentine and Lagosta prospects. Based on the results of these discoveries, Anadarko and its partners began designing an appraisal program and analyzing various development and commercialization options for the area. In addition, the Tubarão offshore exploration well that was drilling at December 31, 2010, was completed and determined to be successful in February 2011. The Company plans to keep at least one rig operating in the basin to continue its exploration and appraisal program in 2011.

Other Anadarko also has active exploration projects in Sierra Leone, New Zealand and Kenya, as well as activities in other overseas new-venture areas. The Company also has a $70 million after-tax net investment in Venezuelan assets. Anadarko's exploration activities in Sierra Leone are located in blocks 6 and 7 in the Liberian basin. In late 2010, Anadarko had a deepwater oil discovery at the Mercury prospect in Sierra Leone. In 2011, the Company plans to drill two to three exploration and appraisal wells in the Liberian basin area. In Cote d'Ivoire, Anadarko holds interests in two blocks located in the Ivorian basin.

Proved Reserves

Reserve and related information for 2010 and 2009 is presented consistent with the requirements of the Modernization of Oil and Gas Reporting rules released by the SEC on December 31, 2008. These revised rules require disclosing oil and gas proved reserves by significant geographic area when such reserves represent more than 15% of total proved reserves, using the 12-month average beginning-of-month commodity prices for the year unless contractual arrangements designate commodity prices, and expand the use of reliable technologies to establish reasonable certainty of the producibility of oil and gas reserves. These rules do not allow for the restatement of prior-year reserve information. All information related to periods prior to 2009 is presented in conformance with prior SEC rules using year-end commodity prices for the estimation of proved reserves; however, prior-year proved reserve data has been reclassified to conform to the current-year presentation of significant geographic areas.

Estimates of proved reserve volumes, net of third-party royalty interests, of natural gas, oil, condensate and NGLs owned at year end are presented in billions of 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. NGLs are separately identified and any associated shrinkage has been deducted from the natural-gas reserve volumes.

Disclosures by geographic area are provided for the United States and International geographic areas. The International geographic area consists of aggregate proved reserves located in Algeria, China and Ghana, each representing 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)
As of December 31, 2010				
Proved				
Developed				
United States	**5,982**	**303**	**222**	**1,523**
International	**—**	**150**	**—**	**150**
Undeveloped				
United States	**2,135**	**195**	**85**	**635**
International	**—**	**101**	**13**	**114**
Total proved	**8,117**	**749**	**320**	**2,422**
As of December 31, 2009				
Proved				
Developed				
United States	5,884	300	199	1,480
International	—	144	—	144
Undeveloped				
United States	1,880	200	61	574
International	—	89	17	106
Total proved	7,764	733	277	2,304

The Company's estimates of proved reserves, proved developed reserves (PDPs) and proved undeveloped reserves (PUDs) at December 31, 2010, 2009 and 2008, 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 filed any information with any other federal authority or agency with respect to its estimated total proved reserves at December 31, 2010. Annually, Anadarko reports gross proved reserves of operated properties in the United States to the U.S. Department of Energy; these reserves are derived from the same data from which its proved reserves of such properties are estimated 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.

Proved Reserves The Company had proved reserves consisting of 8.1 trillion cubic feet (Tcf) of natural gas, 749 MMBbls of oil and condensate and 320 MMBbls of NGLs, totaling 2,422 MMBOE at December 31, 2010, compared to 2,304 MMBOE at December 31, 2009. This results in a year-end 2010 product mix of 56% natural gas, 31% oil and condensate and 13% NGLs, as compared to a year-end 2009 product mix of 56% natural gas, 32% oil and condensate and 12% NGLs, and a year-end 2008 product mix of 59% natural gas, 31% oil and condensate and 10% NGLs. The combined liquids portion of the Company's product mix has increased from 41% at the end of 2008 to 44% at the end of 2010, which is consistent with the Company's efforts to focus on its liquids-rich opportunities.

Proved Undeveloped Reserves The Company had PUDs consisting of 2.1 Tcf of natural gas, 296 MMBbls of oil and condensate, and 98 MMBbls of NGLs, totaling 749 MMBOE at December 31, 2010, compared to 680 MMBOE of PUDs at December 31, 2009.

Changes in PUDs Significant changes to PUDs occurring during 2010 are summarized in the table below. Revisions of prior estimates reflect the addition of new PUDs associated with current development plans, revisions to prior PUDs, revisions to infill drilling development plans, as well as the transfer of PUDs to unproved reserve categories due to changes in development plans during 2010. These PUD changes reflect the ongoing evaluation of Anadarko's asset portfolio and alignment with current-year changes to development plans. The Company's year-end development plans are consistent with SEC guidelines for PUD development within five years unless specific circumstances warrant a longer development time horizon.

MMBOE	
PUDs at December 31, 2009	**680**
Revisions of prior estimates	**142**
Extensions, discoveries and other additions	**30**
Conversion to Developed	**(103)**
PUDs at December 31, 2010	**749**

PUD Conversion In 2010, the Company converted 103 MMBOE, or 15% of the total year-end 2009 PUDs to developed status. Approximately 65% of PUD conversions occurred in onshore United States assets, approximately 24% in international assets and the remaining 11% in Gulf of Mexico assets. Anadarko spent approximately $1.5 billion associated with the development of PUDs in 2010. Approximately 58% of total 2010 PUD capital related to two major development projects, El Merk in Algeria and Jubilee in Ghana, and approximately 29% related to domestic development programs in the Rockies and the Southern and Appalachia Regions. The remaining 13% of 2010 PUD development spending was associated with Gulf of Mexico, Alaska and other international development projects.

Development Plans The Company annually reviews all PUDs to ensure an appropriate plan for development exists. Typically, onshore United States PUDs are converted to PDPs within five years. Projects such as EOR, arctic development, deepwater development and international programs may take longer than five years. At December 31, 2010, all of the Company's onshore United States PUDs were scheduled to be developed within five years, with the exception of the Salt Creek EOR project. Approximately 8% of the Company's year-end 2010 PUDs were associated with Algeria, Salt Creek EOR and Gulf of Mexico projects with estimated development time periods in excess of five years.

At December 31, 2010, the Company had 134 MMBOE of pre-2006 PUDs that remain undeveloped five years or more after disclosure as PUDs. Approximately 71% of these PUDs are located in Algeria and are being developed according to an Algerian government-approved plan. Nearly all of the Algerian PUDs are associated with the El Merk development project located in Block 208 in the Berkine basin. The initial El Merk development plan prepared in 1998 and 1999 was approved by the Algerian government in April 2003. Further evaluation, including an analysis of the results from a continuing drilling program, resulted in a revised El Merk exploitation license submission in 2005, which was subsequently approved by the Algerian regulatory authority in 2007. Site preparation was initiated in 2008 and construction of the El Merk CPF is continuing. As of year-end 2010, 73 wells have been drilled in the El Merk fields and drilling is continuing in 2011. The Reservoir Development Plan currently includes a total of 141 wells for full development. The overall El Merk project was approximately 65% complete at December 31, 2010. First oil production from the El Merk fields is expected to occur around the beginning of 2012.

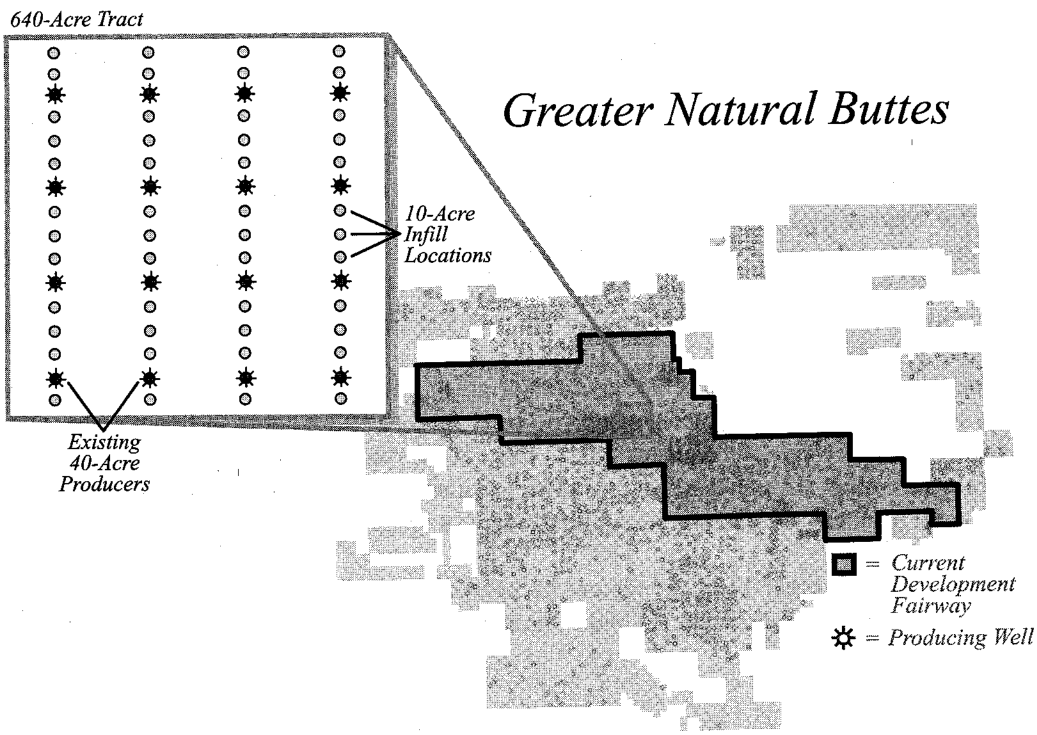
Another 22% of the Company's pre-2006 PUDs are associated with the Salt Creek EOR single-development project located in the Rockies. Since 2003, Anadarko has invested an average of $60 million per year to develop various phases of the Salt Creek integrated EOR project and has plans to continue significant spending levels in the future. Nearly all of the remaining pre-2006 PUDs are associated with Gulf of Mexico sidetrack opportunities where seasonal restrictions limit development activities. The Company expects to take advantage of these opportunities over the next two years, when permitted to resume drilling in the Gulf of Mexico.

Technologies Used in Proved Reserve Estimation In establishing reserves, the SEC allows the use of techniques that have been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In general, the Company uses numerous data elements and analysis techniques in the estimation of proved reserves. These data elements and techniques include, but are not limited to, production tests, well performance data, decline curve analysis, wireline logs, core data, pressure transient analysis, seismic data and interpretation, computational simulation and material balance calculations.

The Company estimates it has 75 MMBOE of proved reserves, or 3% of the Company's total proved reserves, that are supported by the use of reliable technologies. Reserve growth associated with the use of reliable technology can be attributed primarily to recording reserves more than one location away from production, increasing recovery factor estimates or extending down-dip reservoir limits.

Reliable technologies have been used in a limited number of onshore United States producing fields to prove formation continuity more than one location away from production, accounting for less than 2% of the Company's total proved reserves. These reserves are primarily associated with the Greater Natural Buttes area where a selected 10-acre infill drilling program is ongoing on sections previously drilled on 40-acre spacing. An illustration of the application of this program in the Greater Natural Buttes area is included below. The reliable technology associated with this application includes geological mapping and cross-sections based on well log data, decline curve projections from existing producing wells, volumetric calculations, whole and sidewall core analysis, computational simulation, reservoir pressure estimates and analog data. In other onshore United States areas of the Company, similar reliable technology has been used to prove reservoir continuity more than one location away from production, accounting for insignificant reserves volumes.



Reliable technology such as pressure gradient data was employed to extend the down-dip limits of a reservoir. In addition, technology such as drill stem tests, interference testing and water injectivity testing was used to support analog data for recovery factor estimating in a newly developed field. These combined account for approximately 1% of total Company proved reserves.

Internal Controls over Reserve Estimation Anadarko's estimates of proved reserves and associated future net cash flows at December 31, 2010, were made solely by the Company's engineers and are the responsibility of management. The Company requires that reserve 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, costs, net revenues and ultimate recoverable reserves. Management within each region approves the QREs' reserve estimates each quarter and annually. All QREs receive ongoing education on the fundamentals of SEC reserves reporting through the Company's reserves manual and internal training programs administered by the Corporate Reserve Group (CRG).

The CRG ensures confidence in the Company's reserve estimates by maintaining internal policies for estimating and recording reserves in compliance with applicable SEC definitions and guidance. Compliance with the SEC reserve 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 reserve reviews and approving the Company's reserve estimates. The Director–Reserve Administration and the Corporate Reserve Manager manage the CRG and report to the Vice President–Corporate Planning. The Vice President–Corporate Planning reports to the Company's Senior Vice President, Finance and Chief Financial Officer, who in turn reports to the Chief Executive Officer. The Audit Committee of the Company's Board of Directors meets with management, members of the CRG, and independent petroleum consultants Miller and Lents, Ltd. (M&L), to discuss matters and policies related to reserves.

The Company's principal engineer, who is primarily responsible for overseeing the preparation of proved reserve estimates, has over 24 years of experience in the oil and gas industry, including over 10 years as either a reserve evaluator or manager. Further professional qualifications include a degree in petroleum engineering, extensive internal and external reserve training, and asset evaluation and management. In addition, the principal engineer is an active participant in industry reserve seminars, professional industry groups and has been a member of the Society of Petroleum Engineers for over 24 years.

Third-Party Procedures and Methods Review 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, 2010, were reviewed by M&L. The purpose of the review was to determine that 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 review 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 review consisted of 17 fields which included major assets in the United States and Africa, and encompassed approximately 83% of the Company's estimates of proved reserves and future net cash flows at December 31, 2010. 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 its reserve estimation and reporting process.

Sales Volumes, Prices and Production Costs

The following table provides the Company's annual sales volumes, average sales prices and average production costs per BOE from continuing operations for each of the last three years. The Company's sales volumes for 2010, 2009 and 2008 were 235 MMBOE, 220 MMBOE and 206 MMBOE, respectively. 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.

	Sales Volumes				Average Sales Prices (1)			Average
	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)	Production Costs (2) (Per BOE)
2010								
United States								
Greater Natural Buttes	**107**	**1**	**4**	**23**	**$ 3.92**	**$ 66.50**	**$ 39.08**	**$ 9.65**
Other United States	**722**	**47**	**19**	**186**	**4.15**	**75.08**	**43.84**	**8.56**
Total United States	**829**	**48**	**23**	**209**	**4.12**	**74.96**	**43.07**	**8.68**
International	**—**	**26**	**—**	**26**	**—**	**78.52**	**—**	**7.56**
Total	**829**	**74**	**23**	**235**	**4.12**	**76.22**	**43.07**	**8.56**
2009								
United States								
Greater Natural Buttes	100	1	3	21	$ 3.13	$ 48.84	$ 33.68	$ 9.43
Other United States	709	43	14	175	3.68	58.75	31.00	8.50
Total United States	809	44	17	196	3.61	58.56	31.42	8.59
International	—	24	—	24	—	59.01	—	6.01
Total	809	68	17	220	3.61	58.72	31.42	8.30
2008								
United States								
Greater Natural Buttes	91	1	1	17	$ 6.49	$ 78.11	$ 64.67	$ 10.71
Other United States	659	39	13	162	7.86	96.54	55.65	9.91
Total United States	750	40	14	179	7.69	96.20	56.11	9.99
International	—	27	—	27	—	95.83	—	9.02
Total	750	67	14	206	7.69	96.05	56.11	9.86

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, 2010, Anadarko was contractually committed to deliver approximately 750 Bcf of natural gas to various customers in the United States through 2021. These contracts have various expiration dates with approximately 45% of the Company's current commitment to be delivered in 2011, and 90% by 2015. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves.

Drilling Program

The Company's 2010 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. As a result of the Moratorium, the Company redirected 7% of total budgeted 2010 capital from the Gulf of Mexico to onshore United States, with particular emphasis on liquids-rich areas. In accordance with the Moratorium, the Company ceased all drilling in the Gulf of Mexico, which resulted in the suspension of two operated wells (Lucius and Nansen) and one non-operated deepwater well (Vito). The Moratorium was lifted October 12, 2010, but the BOEMRE has not approved new drilling permits. Exploration activity in 2010 consisted of 205 gross completed wells, which included 192 onshore U.S. wells, four offshore Gulf of Mexico wells, and nine international wells. Development activity in 2010 consisted of 1,656 gross completed wells, which included 1,618 onshore wells, two offshore Gulf of Mexico wells, and 36 international wells.

Drilling Statistics

The following table 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
2010							
United States	**84.3**	**1.2**	**85.5**	**1,027.9**	**3.6**	**1,031.5**	**1,117.0**
International	**—**	**3.6**	**3.6**	**11.2**	**—**	**11.2**	**14.8**
Total	**84.3**	**4.8**	**89.1**	**1,039.1**	**3.6**	**1,042.7**	**1,131.8**
2009							
United States	30.6	5.0	35.6	587.2	7.3	594.5	630.1
International	—	3.3	3.3	10.7	—	10.7	14.0
Total	30.6	8.3	38.9	597.9	7.3	605.2	644.1
2008							
United States	12.1	4.6	16.7	1,566.1	8.0	1,574.1	1,590.8
International	—	1.6	1.6	4.9	0.4	5.3	6.9
Total	12.1	6.2	18.3	1,571.0	8.4	1,579.4	1,597.7

The following table 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, 2010.

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion	
	Exploration	Development	Exploration	Development
United States				
Gross	46	311	120	287
Net	16.3	175.7	44.0	202.6
International				
Gross	6	3	23	12
Net	2.3	0.8	8.1	3.0
Total				
Gross	52	314	143	299
Net	18.6	176.5	52.1	205.6

Productive Wells

At December 31, 2010, the Company had an ownership interest in productive wells as follows:

	Oil Wells*	Gas Wells*
United States		
Gross	4,219	27,890
Net	3,249.5	17,308.8
International		
Gross	315	—
Net	78.7	—
Total		
Gross	4,534	27,890
Net	3,328.2	17,308.8

* Includes wells containing multiple completions as follows:

Gross	361	1,977
Net	335.1	1,557.0

Properties and Leases

The following schedule shows the developed lease, undeveloped lease and fee mineral acres in which Anadarko held interests at December 31, 2010.

	Developed Lease		Undeveloped Lease		Fee Minerals		Total	
thousands of acres	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States								
Onshore	5,074	2,993	6,480	2,915	10,226	8,379	21,780	14,287
Offshore	338	169	2,611	1,741	—	—	2,949	1,910
Total United States	5,412	3,162	9,091	4,656	10,226	8,379	24,729	16,197
International	370	97	45,343	22,105	—	—	45,713	22,202
Total	5,782	3,259	54,434	26,761	10,226	8,379	70,442	38,399

MIDSTREAM PROPERTIES AND ACTIVITIES

Anadarko invests in midstream (gathering, processing, treating and transporting) systems to complement its oil and gas operations in regions where the Company has natural-gas production. Through ownership and operation of these facilities, the Company is able to better manage costs associated with bringing on new production and enhance the value received for gathering, processing, treating and transporting the Company's production. In addition, Anadarko's midstream business also provides midstream services to third-party customers, including major and independent producers. Anadarko generates revenues from its midstream activities through a variety of agreements including fixed-fee, percent-of-proceeds and keep-whole agreements. For 2011, Anadarko plans to allocate approximately 15% of the Company's capital budget to the midstream segment.

At the end of 2010, Anadarko had 29 gathering systems located throughout major onshore producing basins in Wyoming, Colorado, Utah, New Mexico, Kansas, Oklahoma, Pennsylvania and Texas. The Marcellus and Eagleford shale areas were significant new focus areas for midstream activity in 2010. Anadarko's midstream business added gas gathering capacity in excess of 180 MMcf/d in the Marcellus shale play and 100 MMcf/d, expandable to 225 MMcf/d, in the Eagleford shale area. In addition, an oil gathering system that can be expanded to handle 60,000 barrels per day (Bbls/d) or more was brought online in the Eagleford shale area in 2010. In 2011, the Company's midstream investment will continue to be focused in the Company's liquids-rich growth plays in the Maverick basin, Delaware basin, Wattenberg and Greater Natural Buttes areas as well as the Marcellus shale area.

Western Gas Partners, LP (WES), a consolidated subsidiary of Anadarko, is a publicly traded limited partnership formed by Anadarko to own, operate, acquire and develop midstream assets. In addition to the assets transferred to WES in connection with its 2008 initial public offering, Anadarko has transferred additional midstream assets to WES, including the 2010 transfers of the Wattenberg and Granger systems, in exchange for additional WES common units, general partner units and cash. In January 2011, WES entered into a purchase and sale agreement with a third party to acquire a processing plant and related gathering systems located in the Rocky Mountains area. This acquisition is expected to close in the first quarter of 2011 subject to regulatory approval and other customary closing conditions. At December 31, 2010, Anadarko held a 46.5% limited partner interest in WES, as well as a 2% general partner interest and incentive distribution rights.

The following table provides information regarding Company-owned midstream assets by geographic regions at December 31, 2010.

Area	Asset Type	Miles of Gathering Pipelines	Total Horsepower	2010 Average Throughput (MMcf/d)
Rocky Mountains	Gathering, Processing and Treating	9,470	1,089,000	3,010
Mid-Continent and other	Gathering	2,470	104,000	150
Texas	Gathering and Treating	1,670	117,000	710
Total		13,610	1,310,000	3,870

MARKETING ACTIVITIES

The Company's marketing segment actively manages Anadarko's natural-gas, crude-oil, condensate and NGLs 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, which in turn, better positions the Company to fully utilize transportation capacity, attract creditworthy customers, facilitate efforts to maximize prices received and minimize balancing issues with customers and pipelines during operational disruptions.

The Company sells natural gas under a variety of contracts 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 and NGLs 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 *Energy Price Risk* under Item 7A of this Form 10-K.

Natural Gas Natural gas continues to fulfill a significant portion of North America's energy needs and the Company believes the importance of natural gas will continue. Anadarko markets its natural-gas production to maximize its 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 also 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 United States 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, jet and diesel 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 heavy fuel oil blend stock market. 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, jet and diesel fuel. The Company also purchases and sells third-party-produced crude oil, condensate and NGLs in the Company's domestic and international market areas, as well as utilizes contracted NGLs storage facilities to capture market opportunities and to help minimize fractionation and downstream infrastructure disruptions.

CURRENT MARKET CONDITIONS AND COMPETITION

In 2008, most segments in the global economy experienced a sharp downturn. Markets improved in 2009 and 2010; however, significant economic uncertainty continues. This economic uncertainty, along with recent commodity price volatility, has made the creditworthiness, liquidity and financial position of the Company's counterparties difficult to evaluate. For this reason, the Company has emphasized its monitoring of counterparty risk. Although Anadarko has not experienced any material financial losses associated with third-party credit deterioration, in certain situations the Company has declined to transact with some counterparties and has changed its sales terms to require some counterparties to pay in advance or post letters of credit for purchases.

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 industrial, commercial and individual consumers.

SEGMENT INFORMATION

For additional information on operations by segment location, see *Note 19—Segment Information* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

For additional information on risk associated with foreign operations, see *Risk Factors* under Item 1A of this Form 10-K.

EMPLOYEES

At December 31, 2010, the Company had approximately 4,400 employees. Anadarko considers its relations with its employees to be satisfactory. The Company's employees are not represented by any union. The Company has had no work stoppages or strikes associated with its employees.

REGULATORY MATTERS, ENVIRONMENTAL AND ADDITIONAL FACTORS AFFECTING BUSINESS

Environmental, Health and Safety Regulations

Anadarko's business operations are subject to numerous international, federal, state and local environmental, health and safety laws and regulations pertaining to the release, emission or discharge of materials into the environment; the generation, storage, transportation, handling and disposal of materials (including solid and hazardous wastes); the occupational health and safety of employees; or otherwise relating to the prevention, mitigation or remediation of pollution, or the preservation or protection of natural resources, wildlife or the environment. The more significant of these existing environmental, health and safety laws and regulations include the following United States 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 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 treatment, storage and disposal of solid wastes, including hazardous wastes.
- The U.S. Federal 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 significantly 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 U.S. 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 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 these 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 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.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards and water quality standards, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, 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 and compliance and mitigation and remediation obligations in the United States.

As a result of the Deepwater Horizon events, the Company has reviewed its potential responsibilities under both OPA and CWA. 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 Environmental Protection Agency 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 Department of Justice (DOJ), on behalf of the federal agencies involved in the spill response, filed a civil lawsuit in the United States District Court for the Eastern District of 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. For additional information, see *Note 2—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, 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, 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 customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental, 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, 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 or results of operations or cash flows, but new or more stringently applied or enforced 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 required to comply with BOEMRE regulations, which currently 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 required 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. BOEMRE 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 in order to satisfy any new regulatory requirements, or to adapt to changes in the Company's operations.

Currently, 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, which detail procedures for 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), and representatives of relevant governmental agencies. The Plans must be approved by the BOEMRE.

As part of the Company's oil spill-response preparedness, and included 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.

At December 31, 2010, CGA equipment includes one High Volume Open Sea Skimmer System (HOSS) barge, four 46-foot skimming vessels, three Marco skimmers, and two Egmopol skimmers. In addition, CGA equipment also consists of:

- Nine Fast Response Units;
- One rope mop;
- Two Foilex skim packages;
- Two 4-drum skimmers (Magnum 100);

- Two 2-drum skimmers (TDS 118);
- Eleven sets of Koseq skimming arms;
- Two Aqua Guard Triton RBS;
- Four oil storage barges (249 barrels);
- Nine tanks (100 barrels, primary); and
- Eight tanks (100 barrels, secondary).

Auto boom, beach boom, and fire boom is 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 on order, and is expected to have a 56-foot skimming vessel available in the near future.

CGA coordinates bareboat charters with Marine Spill Response Corporation (MSRC). MSRC is responsible for inspecting, maintaining, storing and calling out CGA equipment. MSRC has positioned CGA's equipment and materials in a ready state at various staging areas around the Gulf of Mexico. In the event of a spill, MSRC stands ready to mobilize all of its equipment and materials, including those from CGA. MSRC has a fleet of 15 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 is 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 42 skimmers with an Effective Daily Recovery Capacity (EDRC) of 221,051 barrels. At December 31, 2010, the following equipment is available through the various regions:

- Fifteen Responder Class OSRVs;
- Twenty-nine smaller OSRVs;
- Five Fast Response Vessels;
- Nineteen offshore barges;
- Fifty-one shallow water barges (non self-propelled);
- Seventeen shallow water barges (self-propelled);
- Fifty-one shallow water push boats;
- Seventy-one towable storage bladders;
- Three towable storage barges (non self-propelled);
- Twenty-one work boats;
- Twenty-three fastanks (900 barrels);
- Six mini towable storage bladders;
- Twelve tanks/seabags;
- Seven small skimming vessels;
- Nine small barges;
- Thirteen small boats;
- One small Oil Spill-Response Barge;
- Fifteen storage tanks/bladders;
- 199,975 feet of ocean boom;
- 103,159 gallons of Corexit 9500 dispersant; and
- 1,500 gallons of Corexit 9527 dispersant.

MSRC has seven Mobile Communications Suites comprising telephone and computer connections, and UHF and VHF marine, aviation and business band radios. One C-130 dispersant aircraft and one King Air dispersant/spotter aircraft are also available for MSRC member use.

MSRC also handles the maintenance and mobilization of CGA non-marine equipment. MSRC 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, MSRC 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.

The Company also has in place a contract with the National Response Corporation (NRC), a service provider for emergency and crisis management response capabilities (including oil spills). NRC is included as a provider in the Company's federally approved oil spill-response plans. NRC consists of a headquarters-based International Operations Center (IOC) in Great River, New York, with a team of operation, planning, logistics, finance, safety and administration support specialists. Equipment locations are staged in the Northeast, Southeast, South, Pacific Northwest, West, Caribbean and the Virgin Islands. In addition, NRC has an independent contractor's network to further supplement NRC's equipment and personnel.

NRC has an EDRC of 747,569 barrels and temporary storage of 18,444 barrels and an agreement with ASI to utilize ASI's DC-3 dispersant spray aircraft. NRC is currently in the process of increasing the dispersant stockpile with Corexit 9500. At December 31, 2010, the following equipment is listed for the various locations:

- 107,200 feet of 18" and 42" Boom;
- Sixty-six portable storage tanks with 8,334 barrels of storage;
- Forty-six skimmers with an EDRC of 295,896 barrels and 24 barrels of storage; and
- Eight vacuum systems with an EDRC of 48,342 barrels and 180 barrels of storage.

Internationally, Anadarko has in place emergency and oil spill-response plans for each of its exploration and operational activities around the globe. Each plan satisfies the requirements of the 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 (OSR), a global emergency and oil spill-response organization headquartered in London. OSR maintains specialized equipment in a ready state for deployment in the event such equipment is needed by one of its members. OSR is mainly available for response internationally, but their equipment is registered with the United States Coast Guard for domestic use if needed.

Two Hercules aircraft are available for dispersant application or equipment transport, located in the United Kingdom and Singapore. 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. OSR has 3 ADDS Packs–one in the United Kingdom, one in Bahrain, and one in Singapore. If additional aircraft are needed, OSR retains an aircraft broker so that an aircraft can be charted. For international operations, the majority of equipment will be air freighted. Fast response trailers are available, if within the United Kingdom.

OSR 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 reels of 656.167 feet (200 meters) and located in the United Kingdom, Bahrain, and Singapore. Fireboom systems are currently on order. A variety of nearshore boom exists for spill containment.

Additionally OSR can provide 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. OSR also has a wide range of oiled wildlife equipment in conjunction with the Sea Alarm Foundation.

The Company has also entered into contractual commitments to access subsea intervention, containment, capture and shut-in capacity (Containment) for deepwater exploration wells. CGA has contracted with Helix Energy Solutions Group, on behalf of its membership, for the provision of these Containment assets, which will initially provide processing capacity of 45,000 Bbls/d of oil, 60,000 Bbls/d of liquids, and flaring of 80 MMcf/d of natural gas from the vessel HP-1, and burning 10,000 Bbls/d of oil from the vessel Q4000. The system, known as the Helix Fast Response System, currently operates at up to 8,000-feet of sea water depth, and is rated at a 10,000 psi shut-in capability. Member operators are considering various capacity expansion options.

In addition to Anadarko's membership in CGA, NRC and OSR, and in light of the Deepwater Horizon events in the Gulf of Mexico, the Company is participating 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, only 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 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 and defensible and is customary with practices in the oil and gas industry, subject to such exceptions that, in the opinion of legal counsel for the Company, are not so material as to detract substantially from the use of such properties.

The 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 and 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 End of 2011	Position
James T. Hackett	57	Chairman of the Board and Chief Executive Officer
R. A. Walker	54	President and Chief Operating Officer
Robert P. Daniels	52	Senior Vice President, Worldwide Exploration
Robert G. Gwin	48	Senior Vice President, Finance and Chief Financial Officer
Charles A. Meloy	51	Senior Vice President, Worldwide Operations
Robert K. Reeves	54	Senior Vice President, General Counsel and Chief Administrative Officer
M. Cathy Douglas	55	Vice President and Chief Accounting Officer

Mr. Hackett was named Chief Executive Officer in December 2003 and assumed the additional role of Chairman of the Board in January 2006. He also served as President from December 2003 to February 2010. Prior to joining Anadarko, he served as President and Chief Operating Officer of Devon Energy Corporation following its merger with Ocean Energy, Inc. in April 2003. Mr. Hackett served as President and Chief Executive Officer of Ocean Energy, Inc. from March 1999 to April 2003 and as Chairman of the Board from January 2000 to April 2003. He currently serves as a director of Fluor Corporation, Halliburton Company and The Welch Foundation.

Mr. Walker was named Chief Operating Officer in March 2009 and assumed the additional role of President in February 2010. He previously served as Senior Vice President, Finance and Chief Financial Officer from September 2005 until his appointment as Chief Operating Officer. Prior to joining Anadarko, he served as Managing Director for the Global Energy Group of UBS Investment Bank from 2003 to 2005. He has served as a director of Temple-Inland, Inc. since November 2008 and as a director of CenterPoint Energy, Inc. since April 2010. Since August 2007, he has also served as director of Western Gas Holdings, LLC, the general partner of WES, and served as the general partner's Chairman of the Board from August 2007 to September 2009.

Mr. Daniels was named Senior Vice President, Worldwide Exploration in December 2006. Prior to this position, he served as Senior Vice President, Exploration and Production since May 2004 and 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 Senior Vice President, Finance and Chief Financial Officer in March 2009 and had previously served as Senior Vice President since March 2008. He also has served as Chairman of the Board of Western Gas Holdings, LLC since October 2009 and as a director since August 2007. Mr. Gwin also served as President of Western Gas Holdings, LLC from August 2007 to September 2009 and as Chief Executive Officer of Western Gas Holdings, LLC from August 2007 to January 2010. He joined Anadarko in January 2006 as Vice President, Finance and Treasurer. Prior to joining Anadarko, he served as President and CEO of Prosoft Learning Corporation from November 2002 to November 2004 and as Chairman from November 2002 to February 2006, and prior to that served as its Chief Financial Officer from August 2000 to November 2002. Previously, Mr. Gwin spent 10 years at Prudential Capital Group in merchant banking roles of increasing responsibility, including serving as Managing Director with responsibility for the firm's energy investments worldwide.

Mr. Meloy was named Senior Vice President, Worldwide Operations in December 2006 and had served as Senior Vice President, Gulf of Mexico and International Operations since the acquisition of Kerr-McGee in August 2006. Prior to joining Anadarko, he served Kerr-McGee 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 Deep Water from 2000 to 2002. Mr. Meloy has also served as a director of Western Gas Holdings, LLC since February 2009.

Mr. Reeves was named Senior Vice President, General Counsel and Chief Administrative Officer in February 2007 and served as Corporate Secretary from February 2007 to August 2008. He had 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 also served as a director of Key Energy Services, Inc., a publicly traded oilfield services company, since October 2007, and as a director of Western Gas Holdings, LLC since August 2007.

Ms. Douglas was named Vice President and Chief Accounting Officer in November 2008 and had served as Corporate Controller from September 2007 to March 2009. She served as Assistant Controller from July 2006 to September 2007. Ms. Douglas 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. She joined Anadarko in 1979.

Officers of Anadarko are elected at an organizational meeting of the Board of Directors following the annual meeting of stockholders, which is expected to occur on May 17, 2011, and hold office until their successors are duly elected and shall have qualified. There are no family relationships between any directors or executive officers of Anadarko.

Item 1A. Risk Factors

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

The Company has made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with Company management, 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" 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 prove to be correct. 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 the energy market;*
- *production levels;*
- *reserve levels;*
- *operating results;*
- *competitive conditions;*
- *technology;*
- *the availability of capital resources, capital expenditures and other contractual obligations;*
- *the supply and demand for and the price of natural gas, oil, natural gas liquids (NGLs) and other products or services;*
- *volatility in the commodity-futures market;*
- *the weather;*
- *inflation;*
- *the availability of goods and services;*
- *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;*
- *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;*
- *the outcome of events in the Gulf of Mexico related to the Deepwater Horizon events;*
- *the success of BP Exploration & Production Inc.'s (BP) cleanup efforts related to the Deepwater Horizon events;*
- *current and potential legal proceedings, and environmental or other obligations arising from the Deepwater Horizon events, the Oil Pollution Act of 1990 (OPA) and other regulatory obligations, and the operating agreement (OA) for the Macondo well;*
- *the legislative and regulatory changes that may impact the Company's Gulf of Mexico and international offshore operations resulting from the Deepwater Horizon events;*

- *the Company's ability to resume drilling operations in the Gulf of Mexico;*
- *current and potential legal proceedings, environmental or other obligations related to or arising from Tronox Incorporated (Tronox);*
- *the creditworthiness of the Company's counterparties, including financial institutions, operating partners and other parties;*
- *the securities, capital or credit markets;*
- *the Company's ability to repay its debt;*
- *the impact of downgrades to the Company's credit rating, including the ability of the Company to access capital and remain liquid;*
- *the outcome of any proceedings related to the Algerian exceptional profits tax; and*
- *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 may be subject to claims and liability as a result of being a co-lessee of the Mississippi Canyon Block 252 lease and our ownership of a 25% non-operating leasehold interest in the Macondo exploration well in the Gulf of Mexico, which suffered a blowout and drilling rig explosion in April 2010, resulting in loss of life and a significant oil spill.

In April 2010, the Macondo well in the Gulf of Mexico, in which Anadarko holds a 25% non-operating leasehold interest, discovered hydrocarbon accumulations. During suspension operations, the well blew out, an explosion occurred on the *Deepwater Horizon* drilling rig, and the drilling rig sank, resulting in the release of hydrocarbons into the Gulf of Mexico. Eleven people lost their lives in the explosion and subsequent fire, and others sustained personal injuries. Response and cleanup efforts are being conducted by BP, the operator and 65% owner of the Macondo lease, and by other parties, all under the direction of the Unified Command of the United States Coast Guard (the USCG).

On July 15, 2010, after several attempts to contain the oil spill, BP successfully installed a capping stack that shut in the well and prevented the further release of hydrocarbons. Installation of the capping stack was a temporary solution that was followed by a successful "static kill" cementing operation completed on August 5, 2010. The Macondo well was permanently plugged on September 19, 2010, when BP completed a "bottom kill" cementing operation in connection with the successful interception of the well by a relief well. Investigations by the federal government and other parties into the cause of the well blowout, explosion, and resulting oil spill, as well as other matters arising from or relating to these events, are ongoing.

Based on information provided by BP to the Company, BP has incurred costs of approximately $16.5 billion (including costs associated with USCG invoices totaling $606 million) through December 31, 2010, related to spill response and containment, relief-well drilling, grants to certain Gulf Coast states for cleanup costs, local tourism promotion, monetary damage claims and federal costs. In addition, BP has incurred more than $1.4 billion of costs since December 31, 2010.

BP has sought reimbursement from Anadarko for amounts BP has paid or committed to pay for spill-response efforts, grants, damage claims and costs incurred by the federal government through provisions of the OA, which is the contract governing the relationship between BP and the non-operating OA parties to the Mississippi Canyon Block 252 lease in which the Macondo well is located (Lease). Contractual language in the OA, which governs the relationship among the operator and the two non-operating parties, generally provides that BP, as operator, is entitled to reimbursement of certain costs and expenses from the other working interest owners in proportion to their ownership interest in the well. With respect to the operator's duties and liabilities, the OA provides that BP, as operator, owes duties to the non-operating parties (including Anadarko) to perform the drilling of the well in a good and workmanlike manner and to comply with all applicable laws and regulations. The OA dictates that liability for losses, damages, costs, expenses, or claims involving activities or operations shall be borne by each party in proportion to its participating interest, except that when liability results from the gross negligence or willful misconduct of a party, that party shall be solely responsible for liability resulting from its gross negligence or willful misconduct.

BP has invoiced the Company an aggregate $4.0 billion for what BP considers to be Anadarko's 25% proportionate share of actual costs through December 31, 2010. In addition, BP has invoiced Anadarko for anticipated near-term future costs related to the Deepwater Horizon events. Anadarko has withheld reimbursement to BP for Deepwater Horizon event-related invoices pending the completion of various ongoing investigations into the cause of the well blowout, explosion, and subsequent release of hydrocarbons. Final determination of the root causes of the Deepwater Horizon events could materially impact the Company's potential obligations under the OA. To the extent that we are ultimately determined to be responsible for our allocable share of the operator's costs under the OA, we expect our costs to be significantly in excess of the coverage limits under our insurance program.

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 USCG referencing their identification as a "responsible party or guarantor" (RP) under OPA, and the United States Department of Justice (DOJ) has also filed a civil lawsuit against such parties to, among other things, confirm each party's identified RP status. Under OPA, RPs may be held 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 directly related to the spill and spill cleanup. The USCG has directly invoiced the identified RPs for reimbursement of spill-related response costs incurred by the USCG and other federal and state agencies. The identified RPs each received identical invoices for total costs, without specification or stipulation of any allocation of costs between or among the identified RPs. As a 25% non-operating leasehold interest owner in the Lease, and an identified RP under OPA, we may incur liability under currently existing environmental laws and regulations and we may be asked to contribute to the significant and ongoing response and remediation expenses.

To date, as operator, BP has paid all USCG invoices as well as other costs and has sought reimbursement from Anadarko for a 25% portion of these costs through the OA. To the extent that BP discontinues payment or is otherwise unable to satisfy its obligations under OPA for any reason, we would be exposed to additional liability for spill-response and remediation expenses. We have similar exposure relative to the other identified RPs where the failure on the part of any other such identified RPs to satisfy their OPA obligations would expose us to potential liability.

As more facts become known, it is reasonably possible that the Company may be required to recognize a liability related to the Deepwater Horizon events, and that liability could be material to the Company's consolidated financial position, results of operations or cash flows. For example, new information arising out of the legal-discovery process could alter the legal assessment as to the likelihood of the Company incurring a liability related to its existing OA contingent obligations. Moreover, if BP discontinues payment or is otherwise unable to satisfy its obligations, the Company could be required to recognize an OPA-related environmental liability. Similarly, if other identified RPs do not satisfy their obligations under OPA, the Company could incur additional liability. In addition, while OPA contains a $75 million cap for certain costs and damages, exclusive of response and remediation expenses (for which there is no cap), the federal government may take legislative or other action to increase or eliminate the cap, perhaps even retroactively.

As part of its pledge to pay all legitimate claims related to the Deepwater Horizon events, BP announced in June 2010 that it had agreed to contribute $20 billion into an escrow fund over a four-year period to support an independent claims facility, the purpose of which is, according to BP, "to satisfy legitimate claims including natural resource damages and state and local response costs" resulting from the Deepwater Horizon events, with fines and penalties to be excluded from the fund and paid separately. As claims are paid out of this escrow fund, we may be asked to contribute to the payment of such claims pursuant to the OA.

As described above, we are continuing to evaluate our contractual rights and obligations under the OA. If the parties are unable to reach an agreement on liability, one of the possible outcomes is to pursue arbitration under the OA. In any arbitration, the weight to be given to evidence would be determined by the arbitrators. The Company cannot guarantee the success of any such arbitration proceeding.

While we will seek any and all protections available to us pursuant to the OA or otherwise as well as our insurance coverage, an adverse resolution of our contractual rights and responsibilities to BP under the OA or the failure of BP and other identified RPs to satisfy their obligations under OPA could subject us to significant monetary damages and other penalties, such as penalties under the Clean Water Act (CWA), which could have a material adverse effect on our business, prospects, results of operations, financial condition and liquidity.

For all of these reasons or if we were to suffer the other effects described in this risk factor and the following risk factors, our actual liabilities relating to the Deepwater Horizon events could exceed our estimates, and we could incur additional liabilities that we are unable to reasonably estimate at this time, and these events could have a material adverse effect on our financial position, results of operations or cash flows, growth and prospects, including, without limitation, our ability to obtain debt, equity or other financing on acceptable terms, or at all. In addition, the new $5.0 billion senior secured revolving credit facility, which we entered into in September 2010, contains covenants limiting our ability to incur additional debt or pledge additional assets, subject to exceptions. These limitations could adversely affect our ability to obtain additional financing for any future liabilities that may arise in connection with the Deepwater Horizon events.

We have been named as a defendant in various litigation matters as a result of the Deepwater Horizon events. The outcome of existing and future claims could have a material adverse effect on our business, prospects, results of operations, financial condition and liquidity.

Numerous civil lawsuits have been filed against BP and other parties, including the Company, by fishing, boating and shrimping industry groups; restaurants; commercial and residential property owners; certain rig workers or their families; the State of Alabama and several of its political subdivisions; the DOJ; environmental non-governmental organizations; the Plaquemines Parish School Board, a political subdivision of the State of Louisiana; 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.

In August 2010, the United States Judicial Panel on Multidistrict Litigation created Multidistrict Litigation No. 2179 (MDL) to administer essentially all litigation filed in federal court involving Deepwater Horizon event-related claims. Federal Judge Carl Barbier presides over this MDL in the United States District Court for the Eastern District of Louisiana in New Orleans, Louisiana. The court issued a number of case management orders that establish a schedule for procedural matters, discovery and trial of the MDL cases. The court set for trial beginning in June 2011, one or more cases brought against BP as an RP under OPA, to serve as test cases for causation and damage issues. The court has not yet selected the specific OPA test cases to be tried. Also, the court scheduled a February 2012 trial to determine the liability issues and allocable liability among the parties involved in the Deepwater Horizon events. The parties to the MDL are actively engaged in discovery.

On December 15, 2010, the DOJ, on behalf of the federal agencies involved in the spill response, filed a civil lawsuit in the United States District Court for the Eastern District of 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 the lawsuit, the DOJ states that civil penalties under the CWA may be assessed in an amount up to $1,100 per barrel of oil discharged or in cases involving gross negligence or willful misconduct in an amount up to $4,300 per barrel of oil discharged.

Lawsuits seeking to place limitations on the oil and gas industry's operations in the Gulf of Mexico, including those of the Company, have also been filed outside of the MDL by non-governmental organizations against various governmental agencies. These cases are filed in the United States District Court for the Southern District of Alabama, the Eastern District of Louisiana, and the District of Columbia and in the United States Court of Appeals for the Fifth Circuit.

Two separate class action complaints were filed in June and August 2010 in the United States District Court for the Southern District of New York on behalf of purported purchasers of the Company's stock between June 12, 2009, and June 9, 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 District Court for the Southern District of New York consolidated the two cases and appointed The Pension Trust Fund for Operating Engineers and Employees' Retirement System of the Government of the Virgin Islands (the Virgin Islands Group) to act as Lead Plaintiff. In January 2011, the Lead Plaintiff filed its Consolidated Amended Complaint. Prior to filing its Consolidated Amended Complaint, the Lead Plaintiff requested leave from the court to transfer this lawsuit to the United States District Court for the Southern District of Texas. The Company opposes the Lead Plaintiff's request to transfer the case to the District Court for the Southern District of Texas. The court has ordered the parties to brief the transfer of venue issue.

Also in June 2010, a shareholder derivative petition was filed in the 157th Judicial District Court of Harris County, Texas, by a shareholder of the Company against Anadarko (as a nominal defendant) and certain of its officers and current and certain former directors. The petition alleges breaches of fiduciary duties, unjust enrichment, and waste of corporate assets in connection with the Deepwater Horizon events. The plaintiffs seek certain changes to the Company's governance and internal procedures, disgorgement of profits, and reimbursement of litigation fees and costs. In November 2010, the court granted Anadarko's Motion to Dismiss for Lack of Jurisdiction and Special

Exceptions and granted the plaintiffs 120 days to file an Amended Petition. 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. The Board duly considered the demand and in January 2011 determined that it would not be in the best interest of the Company to pursue the issues in the demand letter.

Additional proceedings related to the Deepwater Horizon events may be filed against Anadarko. These proceedings may involve civil claims for damages or governmental investigative, regulatory or enforcement actions. The adverse resolution of any proceedings related to the Deepwater Horizon events could subject us to significant monetary damages, fines and other penalties, which could have a material adverse effect on our business, prospects, results of operations, financial condition and liquidity.

The additional deepwater drilling laws and regulations, delays in the processing and approval of drilling permits and exploration and oil spill-response plans, and other related developments resulting from the recently lifted deepwater drilling moratoria in the Gulf of Mexico may have a material adverse effect on our business, financial condition or results of operations.

In May and July 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), previously known as the Minerals Management Service, an agency of the Department of the Interior (DOI), issued directives requiring lessees and operators of federal oil and gas leases in the Outer Continental Shelf regions of the Gulf of Mexico and Pacific Ocean to cease drilling all new deepwater wells, including wellbore sidetracks and bypasses, through November 30, 2010. These deepwater drilling moratoria (collectively, the Moratorium) prohibited drilling and/or spudding any new wells, and required operators that were in the process of drilling wells to proceed to the next safe opportunity to secure such wells, and to take all necessary steps to cease operations and temporarily abandon the impacted wells. Anadarko ceased all drilling operations in the Gulf of Mexico in accordance with the Moratorium, which resulted in the suspension of operations of two operated deepwater wells (Lucius and Nansen) and one non-operated deepwater well (Vito). The Moratorium was lifted effective October 12, 2010, but the Company is not currently permitted to resume drilling operations in the Gulf of Mexico due to delays in the processing and approval by the BOEMRE of drilling permits and exploration and oil spill-response plans.

The Moratorium did not apply to workovers, completions, plugging and abandonment or production activities; however, in order to continue such activities, the Company is required to comply with additional safety inspection and certification requirements that were set forth in two Notices to Lessees and Operators (NTL) issued by the BOEMRE in June 2010.

On June 8, 2010, the BOEMRE issued an NTL implementing certain safety measures recommended by the Secretary of the Interior in a 30-day safety report to the President of the United States. This NTL requires additional inspections to be conducted and safety measures to be implemented prior to conducting any floating drilling operations with a subsea blowout preventer (BOP) system or surface BOP system, including workovers, completions, and plugging and abandonment operations. On June 18, 2010, the BOEMRE issued another NTL requiring additional information from operators regarding existing and future Exploration Plans, Development and Production Plans and Development and Coordination Documents, all of which may have a significant impact on the timing of and ability to execute exploration and development operations across the Gulf of Mexico.

In particular, on October 14, 2010, the DOI published in the Federal Register an interim final drilling safety rule, effective immediately, enacting into law the June 8, 2010 NTL. The 60-day public comment period closed on December 13, 2010. The rule will become final, either in its current form, or as may be modified by the DOI based on comments received. On October 15, 2010, the DOI published in the Federal Register a final rule requiring operators to develop and implement Safety and Environmental Management Systems (SEMS) for all Gulf of Mexico operations. Effective November 8, 2010, the BOEMRE issued an NTL requiring that every application for a well permit to conduct operations using a subsea blowout preventer (BOP) or surface BOP on a floating facility must be accompanied by information sufficient to demonstrate access to subsea containment resources together with a statement of compliance by an authorized company official covering numerous regulations. Currently, the BOEMRE is evaluating the application of categorical exclusions under the National Environmental Policy Act taking into consideration comments requested in October 2010. In the meantime, the BOEMRE has announced a policy that will require site-specific environmental assessments, as opposed to the categorical exclusion reviews, which could result in further delays in the processing and approval of drilling permits and exploration plans.

On January 11, 2011, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, established by the President of the United States, released its Final Report, entitled "Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling," detailing its findings with respect to the investigation of the Deepwater Horizon events and setting forth recommendations for changes in safety and environmental regulations and laws governing operations in the Gulf of Mexico. As a result, the federal government may issue further safety and environmental laws and regulations regarding operations in the Gulf of Mexico. These additional rules and regulations, delays in the processing and approval of drilling permits and exploration and oil spill-response plans, and possible additional actions could adversely affect and further delay new drilling and ongoing development efforts in the Gulf of Mexico. Among other adverse impacts, these additional measures could delay or disrupt our operations, result in increased costs and limit activities in certain areas of the Gulf of Mexico. We cannot predict with any certainty the full impact of any new laws or regulations, or when we would be able to resume any drilling operations in the Gulf of Mexico.

As a result of the Moratorium and additional inspection and safety requirements issued by the BOEMRE, in May and June 2010, the Company provided notification of force majeure to drilling contractors of four of the Company's contracted deepwater rigs in the Gulf of Mexico. Some of the contracts have provisions that authorize contract termination by either party if force majeure conditions continue for a specified number of consecutive days.

In June 2010, the Company gave written notice of termination to the drilling contractor of a rig placed in force majeure in May 2010, and filed a lawsuit in the United States District Court for the Southern District of Houston against the drilling contractor seeking a judicial declaration that the Company's interpretation of the drilling contract was correct and that the contract terminated on June 19, 2010. The drilling contractor filed an Original Answer in July 2010 denying the Moratorium constituted a force majeure event and asserted that Anadarko had breached the drilling contract. If the Company does not prevail in its claim, it could be obligated to pay the rig contract rate from the contract-termination date through March 2011, the end of the original contract term. The disputed rentals for that period could result in approximately $90 million of cost.

In September 2010, the Company gave written notice of termination to another drilling contractor of a rig that had been placed in force majeure, and the Company filed a lawsuit in the United States District Court for the Southern District of Houston against the drilling contractor seeking a judicial declaration that the Company's interpretation of the drilling contract was correct and that the contract terminated on September 18, 2010. The drilling contractor filed a Motion to Dismiss and an Original Answer in October 2010. The court, acting on its discretion, converted the Motion to Dismiss into a Motion for Summary Judgment and entered a scheduling order for submission of briefs during February and March 2011. If the Company does not succeed in its claim, it could be obligated to pay the rig contract rate from the contract-termination date through March 2013, the end of the original contract term. The disputed rentals for that period could result in approximately $377 million of cost.

In September 2010, the BOEMRE issued an NTL that requires lessees to plug all wells that have been idle for the past five years and decommission related equipment. Lessees were required to submit a company-wide plan for decommissioning facilities and wells. Anadarko completed this plan and does not believe the costs to implement the plan will have a material impact on the Company's consolidated financial position, results of operations or cash flows.

Other governments may also adopt safety, environmental or other laws and regulations that would adversely impact our offshore developments in other areas of the world, including offshore Brazil, New Zealand, West Africa, Mozambique and Southeast Asia. Additional United States or foreign government laws or regulations would likely increase the costs associated with the offshore operations of our drilling contractors. As a result, our drilling contractors may seek to pass increased operating costs to us through higher day-rate charges or through cost escalation provisions in existing contracts.

In addition to increased governmental regulation, we currently expect that insurance costs will increase across the energy industry and certain insurance coverage may be subject to reduced availability or not available on economically reasonable terms, if at all. In particular, the events in the Gulf of Mexico relating to the Macondo well may make it increasingly difficult to obtain offshore property damage, well control and similar insurance coverage. The potential increased costs and risks associated with offshore development may also result in certain current participants allocating resources away from offshore development and discourage potential new participants from undertaking offshore development activities. Accordingly, we may encounter increased difficulty identifying suitable partners willing to participate in our offshore drilling projects and prospects.

Further, as the deepwater Gulf of Mexico (as well as international deepwater locations) lacks the extent of physical and oilfield service infrastructure present in shallower waters, it may be difficult for us to quickly or effectively execute any contingency plans related to future events similar to the Macondo well oil spill.

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

We are, and in the future may become, involved in legal proceedings related to Tronox and, as a result, may incur substantial costs in connection with those proceedings.

Prior to its acquisition by Anadarko, Kerr-McGee Corporation (Kerr-McGee), through an initial public offering and spin-off transaction, disposed of its chemical business. A new publicly traded corporation, Tronox, resulted from this transaction. After the Tronox initial public offering and spin-off, Kerr-McGee was acquired by a wholly owned subsidiary of Anadarko and, as a result, became a wholly owned subsidiary of Anadarko. Under the terms of the Master Separation Agreement (together with all annexes, related agreements, and ancillary agreements to it, the MSA), which was entered into in connection with the Tronox initial public offering, Kerr-McGee agreed to reimburse Tronox for certain qualifying environmental-remediation costs associated with those businesses, subject to certain limitations and conditions. The reimbursement obligation under the MSA was limited to a maximum aggregate reimbursement amount of $100 million. As described below, Tronox has rejected the MSA in its Chapter 11 cases and therefore Kerr-McGee is no longer obligated to reimburse to Tronox under the terms of the agreement. In addition, Tronox and certain third parties have claimed that Kerr-McGee and Anadarko have liability for costs allegedly attributable to the facilities and operations owned by Tronox and for Kerr-McGee's activities prior to the date a subsidiary of Anadarko acquired Kerr-McGee.

In January 2009, Tronox and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of New York (the Court). Subsequently, in May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee asserting a number of claims, including claims for actual and constructive fraudulent conveyance (the Adversary Proceeding). Tronox alleges, among other things, that it was insolvent or undercapitalized at the time it was spun off from Kerr-McGee. Tronox seeks, among other things, to recover an unspecified amount of damages, including interest, from Kerr-McGee and Anadarko as well as the litigation fees and costs. In addition, Tronox seeks to equitably subordinate and/or disallow all claims asserted by Anadarko and Kerr-McGee in the bankruptcy cases.

The United States filed a motion to intervene in the Adversary Proceeding, asserting that it has an independent cause of action against Anadarko, Kerr-McGee and Tronox under the Federal Debt Collection Procedures Act relating primarily to environmental cleanup obligations allegedly owed to the United States by Tronox. That motion to intervene has been granted, and the United States is now a co-plaintiff against Anadarko and Kerr-McGee in the Adversary Proceeding. Anadarko and Kerr-McGee have moved to dismiss the United States' complaint-in-intervention, but that motion currently has been stayed by order of the Court.

In addition, a consolidated class action complaint has been filed in the United States District Court for the Southern District of New York (the District Court) on behalf of purported purchasers of Tronox's equity and debt securities between November 21, 2005, and January 12, 2009 (the Class Period), against Anadarko, Kerr-McGee, several former Kerr-McGee officers and directors, several former Tronox officers and directors and Ernst & Young LLP. The complaint alleges causes of action arising under the Securities Exchange Act of 1934 (the Exchange Act) for purported misstatements and omissions regarding, among other things, Tronox's environmental-remediation and tort claim liabilities. The plaintiffs allege, among other things, that these purported misstatements and omissions are contained in certain of Tronox's public filings, including filings made in connection with Tronox's initial public offering. The plaintiffs seek an unspecified amount of compensatory damages, including interest thereon, as well as litigation fees and costs. Anadarko, Kerr-McGee and other defendants moved to dismiss the class action complaint and in June 2010, the District Court issued an opinion and order dismissing the plaintiffs' complaint against Anadarko, but granted the plaintiffs leave to replead their allegations related to the claim that Anadarko was liable as a successor-in-interest to Kerr-McGee. The District Court further granted in part and denied in part the motions to dismiss by Kerr-McGee and certain of its former officers and directors, but permitted the plaintiffs leave to replead certain of the dismissed claims. The plaintiffs' filed an amended consolidated class action complaint in July 2010. In August 2010, Anadarko moved to dismiss the plaintiffs' amended complaint in whole and Kerr-McGee moved to dismiss the plaintiffs' allegations against it in part. In January 2011, the District Court issued an opinion and order granting Anadarko's motion in part and denying Kerr-McGee's motion in its entirety. The discovery process is ongoing.

In June 2010, Anadarko and Kerr-McGee filed a motion in Tronox's Chapter 11 cases to compel Tronox to assume or reject the MSA. In response to this motion Tronox announced to the Court that it would reject the MSA effective July 22, 2010. In August 2010, the Court entered a Stipulation and Agreed Order among Tronox, Anadarko, and Kerr-McGee authorizing the rejection of the MSA. Following Tronox's rejection of the MSA, Anadarko and Kerr-McGee filed amended proofs of claim (the Proofs of Claim), which include claims for damages arising from such rejection of the MSA. Tronox and several of its creditors objected to the Proofs of Claim. At the end of January 2011, the Court entered a Stipulation and Agreed Order regarding a settlement of the claims by Anadarko and Kerr-McGee against Tronox resulting from its rejection of the MSA. In February 2011, the Company received its agreed-upon claim, in the form of Tronox equity, valued at $29 million.

An adverse resolution of any proceedings related to Tronox could subject us to significant monetary damages and other penalties, which could have a material adverse effect on our business, prospects, results of operations, financial condition and liquidity.

For additional information regarding the nature and status of these and other material legal proceedings, see *Legal Proceedings* under Item 3 of this Form 10-K.

Oil, natural-gas and NGLs prices are volatile. A substantial or extended decline in prices 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. Historically, the markets for oil, natural gas and NGLs have been volatile and may continue to be volatile in the future. For example, in recent years market prices for natural gas in the United States have declined substantially from the highs achieved in 2008 and the rapid development of shale plays throughout North America has contributed significantly to this trend. Factors influencing the prices of oil, natural gas and NGLs are beyond our control. These factors include, among others:

- domestic and worldwide supply of, and demand for, oil, natural gas and NGLs;
- volatile trading patterns in the commodity-futures markets;
- the cost of exploring for, developing, producing, transporting and marketing oil, natural gas and NGLs;
- weather conditions;
- the ability of the members of the Organization of Petroleum Exporting Countries (OPEC) and other producing nations to agree to and maintain production levels;
- the 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;
- the effect of worldwide energy conservation efforts;
- the price and availability of alternative and competing fuels;
- the price and level of foreign imports of oil, natural gas and NGLs;
- domestic and foreign governmental regulations and taxes;
- the proximity to, and capacity of, natural-gas pipelines and other transportation facilities; and
- general economic conditions worldwide.

The long-term effect of these and other factors on the prices of oil, natural gas and NGLs are 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; and
- limiting our access to 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, 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. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, regional, state, tribal and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, 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, federal legislation, proposed in the recently concluded session of Congress and that could be introduced in the current session of Congress, could adversely affect our business, financial condition, results of operations or cash flows, if such legislation were introduced and adopted, which legislation includes the following:

- *Climate Change.* In the recently concluded session of Congress, climate-change legislation establishing a "cap-and-trade" plan for green-house gases (GHGs) was approved by the U.S. House of Representatives. It is not possible at this time to predict whether or when the current session of Congress may act on climate-change legislation. The U.S. Environmental Protection Agency (EPA) has also taken recent action related to GHGs. Based on recent developments, the EPA now purports to have a basis to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act, effective January 2, 2011.
- *Taxes.* The U.S. President's Fiscal Year 2012 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws. These changes include, but are not limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural-gas exploration and development, and (iii) implementing certain international tax reforms.
- *Hydraulic Fracturing.* In the recently concluded session of Congress, legislation amending the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural-gas industry in the hydraulic-fracturing process was considered. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. It is not possible at this time to predict whether or when the current session of Congress may act on hydraulic-fracturing legislation. Such legislation, if adopted, could establish an additional level of regulation and permitting at the federal level.

The recent adoption of derivatives legislation by the U.S. Congress 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 U.S. Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The new legislation was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the new legislation, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain *bona fide* hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require the Company to comply with margin requirements and with certain clearing and trade-execution requirements in connection with its derivative activities, although the application of those provisions to the Company is uncertain at this time. The financial reform legislation may also require the 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. The new legislation and any new 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 legislation 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. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. The Company's revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

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

At December 31, 2010, our total debt was $13.0 billion. We also have various commitments for leases, drilling contracts and transportation and purchase obligations for services and products. Our financial commitments could have important consequences to our business including, but not limited to:

- 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; and
- placing us at a competitive disadvantage compared to our competitors that have less debt and fewer financial commitments.

Additionally, the credit agreement governing our senior secured revolving credit facility (the $5.0 billion Facility) contains a number of covenants that impose greater operating and financial constraints on the Company than those that existed under the previous borrowing arrangements, including restrictions on our ability to:

- incur additional indebtedness;
- sell assets; and
- incur liens.

Our cost of capital under the terms of the $5.0 billion Facility is greater than our cost of capital under the $1.3 billion revolving credit agreement previously in effect due to the increased size and term of the $5.0 billion Facility and then-current market conditions. 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.

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

In June 2010, Moody's Investors Service (Moody's) lowered the Company's senior unsecured credit rating from "Baa3" to "Ba1" and placed the Company's long-term ratings under review for further possible downgrade (the Credit Rating Downgrade), while Standard & Poor's (S&P) and Fitch Ratings (Fitch) each affirmed their "BBB-" rating with a negative outlook. In September 2010, Moody's announced that it concluded its review and confirmed Anadarko's "Ba1" credit rating and changed the rating outlook to stable. As of the date of filing this Form 10-K, no changes in the Company's credit rating have occurred and we are not aware of any current plans of S&P, Fitch or Moody's to revise their respective ratings on our long-term debt. However, we cannot provide assurance that our credit ratings will not be further lowered. Any further downgrade to our credit ratings could negatively impact both our cost of, and our ability to access capital.

As a result of the Credit Rating Downgrade, Anadarko also is more likely to be required to post collateral as financial assurance of its performance under other contractual arrangements, such as pipeline transportation contracts, oil and gas sales contracts, and work commitments. At December 31, 2010, $461 million of letters of credit were provided as assurance of the Company's performance under these types of arrangements, $377 million of which were issued under the $5.0 billion Facility. Further downgrades by the rating agencies may prompt requests by some of Anadarko's business partners for the posting of additional collateral in the form of letters of credit or cash.

In addition, as a result of the Credit Rating Downgrade, the Company's credit thresholds with its derivative counterparties were reduced and in many cases eliminated. There have been no requests for termination or full settlement of derivative liability positions by counterparties, most of which maintain secured positions with respect to these balances as lenders under the $5.0 billion Facility. The aggregate fair value of all derivative instruments with credit-risk-related contingent features for which a net liability position existed on December 31, 2010, was $9 million, net of collateral. Cash collateral held by derivative counterparties from Anadarko was $15 million at December 31, 2010. For additional information, see *Liquidity and Capital Resources* under Item 7 of this Form 10-K.

Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or assumptions underlying our reserve 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 reserve 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 reserve 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 necessarily depend upon a number of variable factors and assumptions, any of which may cause actual results to vary considerably from these estimates, such as:

- historical production from an area compared with production from similar producing areas;
- assumed effects of regulation by governmental agencies;
- assumptions concerning future oil and natural-gas prices, future operating costs and capital expenditures; and
- estimates of future severance and excise taxes, workover 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 current market value of the estimated oil, natural-gas and NGLs reserves attributable to our properties. For the December 31, 2009 and 2010 reserves, in accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are based upon average 12-month sales prices using the average beginning-of-month price, while reserves for all periods prior to December 31, 2009, are based on year-end sales prices. Actual future prices and costs may differ materially from the SEC regulation-compliant prices used for purposes of estimating discounted future net cash flows from proved reserves.

Failure to replace reserves may negatively affect our business.

Our future success depends upon 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 or 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.

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, energy costs, geopolitical issues, the availability and cost of credit, the United States mortgage market and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy.

These factors, combined with volatile oil, natural-gas and NGLs prices, declining business and consumer confidence, and increased unemployment, contributed to the recession in the United States during 2008 and 2009. Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices. If an economic recovery in the United States or abroad is slow or 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 asset impairments.

As a result of mergers and acquisitions, at December 31, 2010, we had approximately $5.3 billion of goodwill on our Consolidated Balance Sheet. Goodwill is not amortized, and must be tested at least annually for impairment, and more frequently when circumstances indicate likely impairment, by applying a fair-value-based test. 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, or other adverse events, such as lower sustained oil and 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, regional, state, tribal, local and foreign laws and regulations relating to environmental protection from the time projects commence until abandonment. These laws and regulations govern, among other things:

- the amounts and types of substances and materials that may be released;
- the issuance of permits in connection with exploration, drilling, production and midstream activities;
- the protection of endangered species;
- the release of emissions;
- the discharge and disposition of generated waste materials;
- offshore oil and gas operations;
- the reclamation and abandonment of wells and facility sites; and
- the remediation of contaminated sites.

In addition, these laws and regulations may impose substantial liabilities for our failure to comply with them or for any contamination resulting from our operations. Future environmental laws and regulations, such as proposed legislation regulating climate change or hydraulic fracturing, 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. For a description of certain environmental proceedings in which we are involved, see *Legal Proceedings* under Item 3 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, Ghana, Mozambique, Brazil, China and other countries. Our operations and financial results could be significantly impacted by conditions in some of these areas, such as the Gulf of Mexico, because we explore and produce extensively in those areas. As a result of this activity, we are vulnerable to the risks associated with operating offshore, including those relating to:

- hurricanes and other adverse weather conditions;
- oil field 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; and
- failure of equipment or facilities.

In addition, we expect to conduct some of our exploration in the deep waters (greater than 1,000 feet) of the Gulf of Mexico, 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 a significant amount of 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 reserve 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 other countries and are subject to political, economic and other uncertainties.

Our operations outside the United States are based primarily in Algeria, Brazil, China, Cote d'Ivoire, Ghana, Indonesia, Liberia, Mozambique and Sierra Leone. As a result, we face political and economic risks and other uncertainties with respect to our international operations. These risks may include, among other things:

- loss of revenue, property and equipment as a result of hazards such as expropriation, war, piracy, acts of terrorism, insurrection, civil unrest and other political risks;
- transparency issues in general and, more specifically, the U.S. Foreign Corrupt Practices Act and other anti-corruption compliance issues;
- increases in taxes and governmental royalties;
- unilateral renegotiation of contracts by governmental entities;
- 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; and
- international monetary fluctuations and changes in the relative value of the U.S. dollar as compared with the currencies of other countries in which we conduct business.

For example, in 2006, the Algerian parliament approved legislation establishing an exceptional profits tax on foreign companies' Algerian oil production and issued regulations implementing this legislation. In response to the Algerian government's imposition of the exceptional profits tax, we notified Sonatrach of our disagreement with the collection of the exceptional profits tax. In February 2009, we initiated arbitration against Sonatrach with regard to the exceptional profits tax. For additional information, see *Note 16—Other Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Recently, outbreaks of civil and political unrest have occurred in several countries in Africa and the Middle East, including countries where we conduct operations, such as Algeria and Cote d'Ivoire. As exhibited by the recent events in Tunisia and Egypt, these outbreaks have in certain instances resulted in the established governing body being overthrown. Continued or escalated civil and political unrest in the countries in which we operate could result in our curtailing operations. For instance, a dispute over a recent election in Cote d'Ivoire has resulted in the establishment of two rival governments. Due to the uncertainty surrounding the civil and political unrest resulting from this disputed election, in February 2011, we suspended our operations in Cote d'Ivoire by declaring force majeure. We are unable to predict when or how the disputed election will be resolved, and when or if we would be able to resume operations in Cote d'Ivoire. In the event that countries in which we operate experience political or civil unrest, especially in events where such unrest leads to an unseating of the established government, our operations in such country 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 benefiting fully 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:

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

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and 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 of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their 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.

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, any of which could result in damage to, or destruction of, oil and natural-gas wells or formations or production facilities and other property and injury to persons. As protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including certain physical damage, blowout/control of well, comprehensive general liability and worker's compensation insurance 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. Key factors that may affect the timing and outcome of such projects include:

- project approvals by joint-venture partners;
- timely issuance of permits and licenses by governmental agencies;
- weather conditions;
- availability of personnel;
- manufacturing and delivery schedules of critical equipment; and
- 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.

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 industrial, commercial and individual consumers. Some of our competitors may have greater and more diverse resources upon 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 oil field 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 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 oil field 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:

- 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;
- title problems;
- other adverse weather conditions; and
- 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 control 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 or control the operation or future development of these non-operated 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 or control 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 gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation.

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

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 classification, nomination and removal of directors, prohibiting stockholder action by written consent and regulating the ability of our stockholders 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 upon their declaration by our Board of Directors and upon our financial condition, results of operations, cash flows, the levels of our capital and exploration expenditures, our 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, including James T. Hackett, our Chairman and Chief Executive Officer, could have an adverse effect on our business. We entered into an employment agreement with Mr. Hackett to secure his employment with us. 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

The Company has no unresolved SEC staff comments that have been outstanding greater than 180 days from December 31, 2010.

Item 3. Legal Proceedings

GENERAL The Company is a defendant in a number of lawsuits and is involved in governmental proceedings arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. The Company has also been named as a defendant in various personal injury claims, including claims by employees of third-party contractors alleging exposure to asbestos, silica and benzene while working at refineries (previously owned by predecessors of acquired companies) located in Texas, California and Oklahoma. While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings will not have a material adverse effect on the consolidated financial position, results of operations or cash flows of the Company.

DEEPWATER HORIZON EVENTS—RELATED PROCEEDINGS In April 2010, the Macondo well in the Gulf of Mexico, in which Anadarko holds a 25% non-operating leasehold interest, discovered hydrocarbon accumulations. During suspension operations, the well blew out, an explosion occurred on the *Deepwater Horizon* drilling rig, and the drilling rig sank, resulting in the release of hydrocarbons into the Gulf of Mexico. Eleven people lost their lives in the explosion and subsequent fire, and others sustained personal injuries. Response and cleanup efforts are being conducted by BP, the operator and 65% owner of the Macondo lease, and by other parties, all under the direction of the Unified Command of the USCG.

On July 15, 2010, after several attempts to contain the oil spill, BP successfully installed a capping stack that shut in the well and prevented the further release of hydrocarbons. Installation of the capping stack was a temporary solution that was followed by a successful "static kill" cementing operation completed on August 5, 2010. The Macondo well was permanently plugged on September 19, 2010, when BP completed a "bottom kill" cementing operation in connection with the successful interception of the well by a relief well. Investigations by the federal government and other parties into the cause of the well blowout, explosion, and resulting oil spill, as well as other matters arising from or relating to these events, are ongoing.

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 USCG referencing their identification as an RP under OPA, and the DOJ has also filed a civil lawsuit against such parties seeking to, among other things, confirm each party's identified RP status. Under OPA, RPs may be held 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 directly related to the spill and spill cleanup. The USCG has directly invoiced the identified RPs for reimbursement of spill-related response costs incurred by the USCG and other federal and state agencies. The identified RPs each received identical invoices for total costs, without specification or stipulation of any allocation of costs between or among the identified RPs. To date, as operator, BP has paid all USCG invoices, thereby satisfying the joint and several obligation of the identified RPs to the USCG for these costs. BP has also made repeated public statements regarding its intention to continue to pay 100% of costs associated with cleanup efforts, claims and reimbursements related to the Deepwater Horizon events.

As a result of the Deepwater Horizon events, numerous civil lawsuits have been filed against BP and other parties, including the Company, by fishing, boating and shrimping industry groups; restaurants; commercial and residential property owners; certain rig workers or their families; the State of Alabama and several of its political subdivisions; the DOJ; environmental non-governmental organizations; the Plaquemines Parish School Board, a political subdivision of the State of Louisiana; 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.

In August 2010, the United States Judicial Panel on Multidistrict Litigation created MDL No. 2179 to administer essentially all litigation filed in federal court involving Deepwater Horizon event-related claims. Federal Judge Carl Barbier presides over this MDL in the United States District Court for the Eastern District of Louisiana in New Orleans, Louisiana. The court issued a number of case management orders that establish a schedule for procedural matters, discovery and trial of the MDL cases. The court set for trial beginning in June 2011, one or more cases brought against BP as an RP under OPA, to serve as test cases for causation and damage issues. The court has not yet selected the specific OPA test cases to be tried. Also, the court scheduled a February 2012 trial to determine the liability issues and allocable liability among the parties involved in the Deepwater Horizon events. The parties to the MDL are actively engaged in discovery.

On December 15, 2010, the DOJ, on behalf of the federal agencies involved in the spill response, filed a civil lawsuit in the United States District Court for the Eastern District of 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 the lawsuit, the DOJ states that civil penalties under the CWA may be assessed in an amount up to $1,100 per barrel of oil discharged or in cases involving gross negligence or willful misconduct in an amount up to $4,300 per barrel of oil discharged.

Lawsuits seeking to place limitations on the oil and gas industry's operations in the Gulf of Mexico, including those of the Company, have also been filed outside of the MDL by non-governmental organizations against various governmental agencies. These cases are filed in the United States District Court for the Southern District of Alabama, the Eastern District of Louisiana, and the District of Columbia and in the United States Court of Appeals for the Fifth Circuit.

Two separate class action complaints were filed in June and August 2010 in the United States District Court for the Southern District of New York on behalf of purported purchasers of the Company's stock between June 12, 2009, and June 9, 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 District Court for the Southern District of New York consolidated the two cases, and appointed the Virgin Islands Group to act as Lead Plaintiff. In January 2011, the Lead Plaintiff filed its Consolidated Amended Complaint. Prior to filing its Consolidated Amended Complaint, the Lead Plaintiff requested leave from the court to transfer this lawsuit to the United States District Court for the Southern District of Texas. The Company opposes the Lead Plaintiff's request to transfer the case to the District Court for the Southern District of Texas. The court has ordered the parties to brief the transfer of venue issue.

Also in June 2010, a shareholder derivative petition was filed in the 157th Judicial District Court of Harris County, Texas, by a shareholder of the Company against Anadarko (as a nominal defendant) and certain of its officers and current and certain former directors. The petition alleges breaches of fiduciary duties, unjust enrichment, and waste of corporate assets in connection with the Deepwater Horizon events. The plaintiffs seek certain changes to the Company's governance and internal procedures, disgorgement of profits, and reimbursement of litigation fees and costs. In November 2010, the court granted Anadarko's Motion to Dismiss for Lack of Jurisdiction and Special Exceptions and granted the plaintiffs 120 days to file an Amended Petition. In September 2010, a purported shareholder made a demand on the Board to investigate allegations of breaches of duty by members of management. The Board duly considered the demand and in January 2011 determined that it would not be in the best interest of the Company to pursue the issues in the demand letter.

These proceedings are at a very early stage; accordingly, the Company currently cannot assess the probability of losses, or reasonably estimate a range of any potential losses related to the proceedings described above. The Company intends to vigorously defend itself, its officers and its directors in these proceedings.

TRONOX PROCEEDINGS In January 2009, Tronox, a former wholly owned subsidiary of Kerr-McGee, and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the Court. Subsequently, in May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee asserting a number of claims, including claims for actual and constructive fraudulent conveyance (the Adversary Proceeding). Tronox alleges, among other things, that it was insolvent or undercapitalized at the time it was spun off from Kerr-McGee. Tronox seeks, among other things, to recover an unspecified amount of damages, including interest, from Kerr-McGee and Anadarko as well as the litigation fees and costs. In addition, Tronox seeks to equitably subordinate and/or disallow all claims asserted by Anadarko and Kerr-McGee in the bankruptcy cases. Anadarko and Kerr-McGee moved to dismiss the complaint in its entirety. In March 2010, the Court issued an opinion granting in part and denying in part Anadarko's and Kerr-McGee's motion to dismiss the complaint. Notably, the Court dismissed, with prejudice, Tronox's request for punitive damages relating to the fraudulent conveyance claims. The Court granted Tronox leave to replead certain of its common law claims, and Tronox filed an amended complaint in April 2010. Anadarko and Kerr-McGee have moved to dismiss three breach of fiduciary duty-related claims in the amended complaint. That motion has been briefed and is awaiting a ruling by the Court. The Adversary Proceeding is set for trial in March 2012.

The United States filed a motion to intervene in the Adversary Proceeding, asserting that it has an independent cause of action against Anadarko, Kerr-McGee and Tronox under the Federal Debt Collection Procedures Act relating primarily to environmental cleanup obligations allegedly owed to the United States by Tronox. That motion to intervene has been granted, and the United States is now a co-plaintiff against Anadarko and Kerr-McGee in the Adversary Proceeding. Anadarko and Kerr-McGee have moved to dismiss the United States' complaint-in-intervention, but that motion currently has been stayed by order of the Court.

In June 2010, Anadarko and Kerr-McGee filed a motion in Tronox's Chapter 11 cases to compel Tronox to assume or reject the MSA. In response to this motion, Tronox announced to the Court that it would reject the MSA effective July 22, 2010. In August 2010, the Court entered a Stipulation and Agreed Order among Tronox, Anadarko, and Kerr-McGee authorizing the rejection of the MSA. Anadarko and Kerr-McGee filed the Proofs of Claim, which include claims for damages arising from such rejection of the MSA. Tronox and several of its creditors have objected to the Proofs of Claim. At the end of January 2011, the Court entered a Stipulation and Agreed Order regarding a settlement of the claims by Anadarko and Kerr-McGee against Tronox resulting from its rejection of the MSA. In February 2011, the Company received its agreed-upon claim, in the form of Tronox equity, valued at $29 million. The Company will continue to monitor events subsequent to the MSA rejection and will assess the impact of future events on the Company's consolidated financial position, results of operations or cash flows.

In August 2010, Tronox filed a motion seeking, among other things, (i) authority to enter into a certain plan support agreement and equity-commitment agreement (together, the Plan Support Agreements) and (ii) approval of procedures for a rights offering. Anadarko and Kerr-McGee filed an objection to the motion. In the objection, Anadarko and Kerr-McGee requested that the Court order mediation of the Adversary Proceeding. Tronox and the United States opposed mediation, citing, in support of their position, a lack of sufficient discovery. The Court declined to order mediation at that time. In September 2010, the Court entered an order authorizing Tronox to enter into the Plan Support Agreements and approved the rights offering procedures. Anadarko and Kerr-McGee are not subject to the rights offering procedures. However, Anadarko and Kerr-McGee reached an agreement with Tronox that will entitle them to receive the economic benefit on account of their claims against Tronox as if they had participated in the rights offering if certain conditions are satisfied.

In September 2010, Tronox filed a Proposed First Amended Joint Plan of Reorganization pursuant to Chapter 11 of the Bankruptcy Code (the Plan) and a related disclosure statement (the Disclosure Statement), which modify and supersede the terms of its plan and disclosure statement filed in July 2010. Tronox subsequently filed further amendments to the Plan and Disclosure Statement. The Plan contemplates, among other things, that (a) the claims of the United States (as well as other federal, state, local or tribal governmental entities having regulatory authority or responsibilities with respect to environmental laws) related to Tronox's environmental liabilities at legacy sites, will be settled through the creation of certain environmental response trusts and a litigation trust, to which Tronox will contribute the following consideration: (i) $270 million in cash, (ii) 88% of the proceeds from the Adversary Proceeding, (iii) certain Nevada assets, including the real property located in Henderson, Nevada, (iv) certain other real property and related assets, and (v) certain insurance and financial assurance assets worth at least $50 million; (b) certain creditors who have asserted tort claims against Tronox arising from, among other things, environmental contamination or chemical or asbestos exposure will receive the following consideration from a trust to be created under the Plan: (i) $13 million in cash, (ii) 12% of the proceeds from the Adversary Proceeding, and (iii) certain insurance assets, including the net proceeds of certain insurance settlements; and (c) certain creditors who have asserted general unsecured claims against Tronox will receive the following consideration: (i) their pro rata share of 50.9% of the common equity of reorganized Tronox and (ii) the right to purchase up to 45.5% of the common equity of reorganized Tronox. Objections to the Plan and Disclosure Statement were filed by various interested parties, including Anadarko and Kerr-McGee.

In September 2010, the Court approved the Disclosure Statement and authorized Tronox to begin soliciting votes to accept or reject the Plan. In October 2010, the Court entered a stipulation between Anadarko and Tronox which provides for allowance of Anadarko's claims for voting purposes only.

In October and November 2010, Tronox filed certain documents central to the Plan as part of the Plan Supplement including, among other things, the Environmental Claims Settlement Agreement and the Tort Claims Trust Agreement. The Plan contemplates that additional documents, including the Anadarko Litigation Trust Agreement, will be filed as part of the Plan Supplement and parties in interest will have an opportunity to object to those documents before they become effective pursuant to the Plan. Also in November 2010, the Court confirmed the Plan, subject to certain modifications and settlements, and entered the order confirming the Plan. Anadarko's objections to the Plan were resolved prior to confirmation. In February 2011, Tronox emerged from bankruptcy. It is unclear what, if any, effect the Plan might have on the Adversary Proceeding or its outcome.

In addition, a consolidated class action complaint has been filed in the United States District Court for the Southern District of New York (the District Court) on behalf of purported purchasers of Tronox's equity and debt securities between November 21, 2005, and January 12, 2009 (the Class Period), against Anadarko, Kerr-McGee, several former Kerr-McGee officers and directors, several former Tronox officers and directors and Ernst & Young LLP. The complaint alleges causes of action arising under the Exchange Act for purported misstatements and omissions regarding, among other things, Tronox's environmental-remediation and tort claim liabilities. The plaintiffs allege, among other things, that these purported misstatements and omissions are contained in certain of Tronox's public filings, including filings made in connection with Tronox's initial public offering. The plaintiffs seek an unspecified amount of compensatory damages, including interest thereon, as well as litigation fees and costs. Anadarko, Kerr-McGee and other defendants moved to dismiss the class action complaint and in June 2010, the District Court issued an opinion and order dismissing the plaintiffs' complaint against Anadarko, but granted the plaintiffs leave to replead their allegations related to the claim that Anadarko was liable as a successor-in-interest to Kerr-McGee. The District Court further granted in part and denied in part the motions to dismiss by Kerr-McGee and certain of its former officers and directors, but permitted the plaintiffs leave to replead certain of the dismissed claims. The plaintiffs filed an amended consolidated class action complaint in July 2010. In August 2010, Anadarko, Kerr-McGee, and several of Kerr-McGee's former officers and directors filed respective motions to dismiss. In January 2011, the District Court issued an opinion and order denying the motions of Kerr-McGee and several former Kerr-McGee officers and directors. The District Court also denied Anadarko's motion to dismiss the remaining Section 20(a) claim under the Exchange Act covering the period beginning on August 10, 2006, through the end of the alleged Class Period. However, the District Court dismissed this claim against Anadarko to the extent it was based on a successor-in-interest theory of liability. The discovery process is ongoing.

These proceedings are at a very early stage; accordingly, the Company currently cannot assess the probability of losses, or reasonably estimate a range of any potential losses related to the proceedings described above. The Company intends to vigorously defend itself, its officers and its directors in these proceedings.

See *Note 2—Deepwater Horizon Events, Note 14—Commitments* and *Note 15—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

OTHER MATTERS The Company is subject to other legal proceedings, claims and liabilities which arise in the ordinary course of its business. In the opinion of Anadarko, the liability with respect to these actions will not have a material effect on the consolidated financial position, results of operations or cash flows of the Company.

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

MARKET INFORMATION, HOLDERS AND DIVIDENDS

As of January 31, 2011, there were approximately 14,560 record holders 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 2010 and 2009.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2010				
Market Price				
High	**$ 73.89**	**$ 75.07**	**$ 58.42**	**$ 78.98**
Low	**$ 60.75**	**$ 34.54**	**$ 36.06**	**$ 55.65**
Dividends	**$ 0.09**	**$ 0.09**	**$ 0.09**	**$ 0.09**
2009				
Market Price				
High	$ 44.00	$ 52.38	$ 66.21	$ 69.37
Low	$ 30.88	$ 37.80	$ 40.28	$ 55.87
Dividends	$ 0.09	$ 0.09	$ 0.09	$ 0.09

The amount of future common stock dividends will depend on earnings, financial condition, capital requirements 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—Dividends* under Item 7 and *Note 13—Share-Based Compensation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth information with respect to the equity compensation plans available to directors, officers and employees of the Company at December 31, 2010.

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	9,545,056	$ 49.15	19,812,498
Equity compensation plans not approved by security holders	—	—	—
Total	9,545,056	$ 49.15	19,812,498

PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PERSONS

In August 2008, the Company announced a share-repurchase program (the Program) to purchase up to $5 billion in shares of common stock. The Program replaces a prior share-repurchase program and is authorized to extend through August 2011; however, the Program does not obligate Anadarko to acquire any specific number of shares and may be discontinued at any time. The following table sets forth information with respect to repurchases made by the Company of its shares of common stock during the fourth quarter of 2010.

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 1-31	345	$ 57.06	—	
November 1-30	33,688	$ 66.15	—	
December 1-31	64,128	$ 67.96	—	
Fourth Quarter 2010	98,161	$ 67.30	—	$ 4,400,000,000

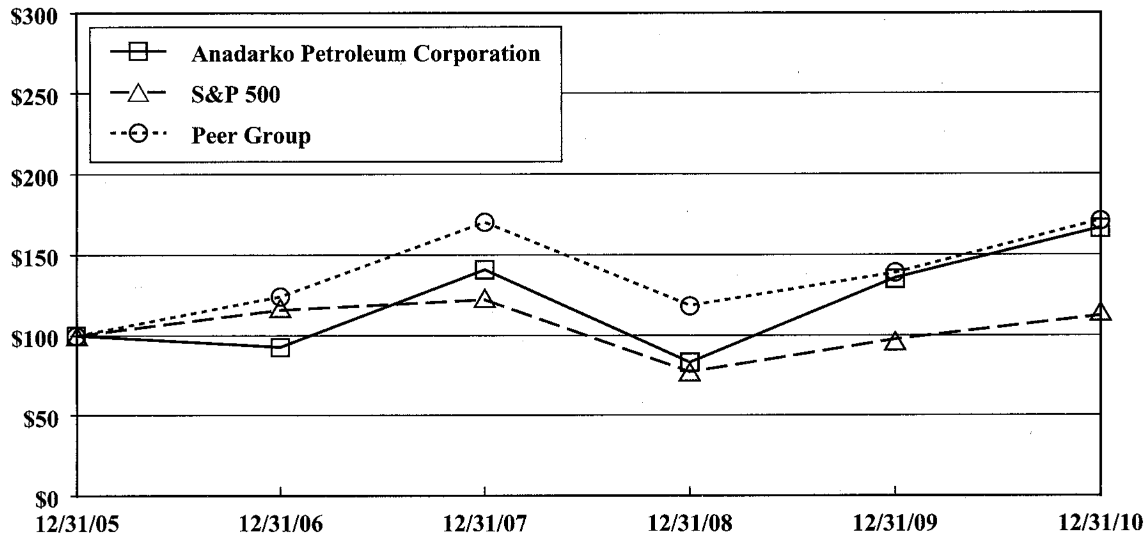
(1) During the fourth quarter of 2010, all purchased shares related to stock received by the Company for the payment of withholding taxes due on employee stock plan share issuances, which are not within the scope of the Program.

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 on Anadarko's common stock relative to the cumulative total returns of the S&P 500 index and a customized peer group of 11 companies. The companies included in the customized 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; Pioneer Natural Resources Company; and Plains Exploration and Production Company.

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



An investment of $100 (with reinvestment of all dividends) is assumed to have been made in the Company's common stock, in the index and in the peer group on December 31, 2005, and its relative performance is tracked through December 31, 2010.

Fiscal Year Ended December 31	2005	2006	2007	2008	2009	2010
Anadarko Petroleum Corporation	$ 100.00	$ 92.56	$ 140.73	$ 83.15	$ 135.68	$ 166.59
S&P 500	100.00	115.80	122.16	76.96	97.33	111.99
Peer Group	100.00	124.08	170.07	118.48	138.97	171.23

Item 6. Selected Financial Data

millions except per-share amounts	**2010**	2009	2008	2007	2006
	Summary Financial Information*				
Sales Revenues	**$ 10,842**	$ 8,210	$ 14,079	$ 11,656	$ 10,116
Gains (Losses) on Divestitures and Other, net	**142**	133	1,083	4,760	114
Reversal of Accrual for DWRRA Dispute	**—**	657	—	—	—
Total Revenues and Other	**10,984**	9,000	15,162	16,416	10,230
Operating Income (Loss)	**1,769**	377	5,601	7,871	4,381
Income (Loss) from Continuing Operations	**821**	(103)	3,220	3,767	2,471
Income from Discontinued Operations, net of taxes	**—**	—	63	11	2,275
Net Income (Loss) Attributable to Common Stockholders	**761**	(135)	3,260	3,778	4,746
Per Common Share (amounts attributable to common stockholders):					
Income (Loss) from Continuing Operations—Basic	**$ 1.53**	$ (0.28)	$ 6.79	$ 8.01	$ 5.33
Income (Loss) from Continuing Operations—Diluted	**$ 1.52**	$ (0.28)	$ 6.78	$ 7.99	$ 5.31
Income from Discontinued Operations—Basic	**$ —**	$ —	$ 0.13	$ 0.02	$ 4.91
Income from Discontinued Operations—Diluted	**$ —**	$ —	$ 0.13	$ 0.02	$ 4.88
Net Income (Loss)—Basic	**$ 1.53**	$ (0.28)	$ 6.92	$ 8.03	$ 10.24
Net Income (Loss)—Diluted	**$ 1.52**	$ (0.28)	$ 6.91	$ 8.01	$ 10.19
Dividends	**$ 0.36**	$ 0.36	$ 0.36	$ 0.36	$ 0.36
Average Number of Common Shares Outstanding—Basic	**495**	480	465	465	460
Average Number of Common Shares Outstanding—Diluted	**497**	480	466	467	463
Cash Provided by Operating Activities—Continuing Operations	**$ 5,247**	$ 3,926	$ 6,447	$ 2,766	$ 4,671
Cash Provided by (Used in) Operating Activities—Discontinued Operations	**—**	—	(5)	134	(178)
Net Cash Provided by Operating Activities	**5,247**	3,926	6,442	2,900	4,493
Capital Expenditures	**$ 5,169**	$ 4,558	$ 4,881	$ 3,990	$ 4,212
Current Debt	**$ 291**	$ —	$ 1,472	$ 1,396	$ 11,471
Long-term Debt	**12,722**	11,149	9,128	11,151	11,520
Midstream Subsidiary Note Payable to a Related Party	**—**	1,599	1,739	2,200	—
Total Debt	**$ 13,013**	$ 12,748	$ 12,339	$ 14,747	$ 22,991
Total Stockholders' Equity	**20,684**	19,928	18,795	16,364	12,403
Total Assets	**$ 51,559**	$ 50,123	$ 48,923	$ 48,451	$ 54,964
Annual Sales Volumes:					
Continuing Operations					
Natural Gas (Bcf)	**829**	809	750	698	558
Oil and Condensate (MMBbls)	**74**	68	67	79	70
Natural Gas Liquids (MMBbls)	**23**	17	14	16	15
Total (MMBOE)**	**235**	220	206	211	178
Discontinued Operations (MMBOE)	**—**	—	—	—	17
Total (MMBOE)**	**235**	220	206	211	195
Average Daily Sales Volumes:					
Continuing Operations					
Natural Gas (MMcf/d)	**2,272**	2,217	2,049	1,912	1,529
Oil and Condensate (MBbls/d)	**201**	187	182	215	193
Natural Gas Liquids (MBbls/d)	**63**	47	39	43	42
Total (MBOE/d)	**643**	604	563	577	489
Discontinued Operations (MBOE/d)	**—**	—	—	—	46
Total (MBOE/d)	**643**	604	563	577	535
Reserves:					
Natural-Gas Reserves (Tcf)	**8.1**	7.8	8.1	8.5	10.5
Oil and Condensate Reserves (MMBbls)	**749**	733	709	843	1,126
Natural-Gas Liquids Reserves (MMBbls)	**320**	277	217	171	138
Total Reserves (MMBOE)	**2,422**	2,304	2,277	2,431	3,011
Number of Employees	**4,400**	4,300	4,300	4,000	5,200

* Consolidated for Anadarko and its subsidiaries. Certain amounts for prior years have been reclassified to conform to the current presentation.
** 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 achieved its key operational objectives in 2010 by increasing sales volumes by approximately 7% year-over-year, reducing oil and gas operating expenses per unit by approximately 9% year-over-year, and adding 359 million barrels of oil equivalent (BOE) of proved reserves. Additionally, the Company continued offshore exploration and appraisal drilling success with an approximate 75% success rate and achieved first oil at the Jubilee field offshore Ghana in 3.5 years following discovery. Anadarko ended 2010 with approximately \$3.7 billion cash on hand and retains the availability of its undrawn five-year \$5.0 billion senior secured revolving credit facility (the \$5.0 billion Facility) less \$377 million in outstanding letter of credit supported by the \$5.0 billion Facility, as well as additional access to credit and capital markets as needed. Management believes that the Company's cash on hand, available borrowing capacity and cash flows from operations position the Company to satisfy its operational objectives and capital commitments.

Mission and Strategy

Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural-gas resources vital to the world's health and welfare. Anadarko employs the following strategy to achieve this mission:

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

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

Exploring in high-potential, proven and emerging basins worldwide provides the Company with growth opportunities. Anadarko's exploration success, which includes 17 offshore discoveries in the last two years, has created value by expanding its future resource potential, while providing the flexibility to manage risk by monetizing discoveries.

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 investments in its businesses to manage through commodity price cycles. Maintaining financial discipline enables the Company to capitalize on the flexibility of its global portfolio, while allowing the Company to pursue new strategic growth opportunities.

Operating Highlights

Significant 2010 operating highlights include the following:

Deepwater Horizon Events

In April 2010, the Macondo well in the Gulf of Mexico, in which Anadarko holds a 25% non-operating leasehold interest, discovered hydrocarbon accumulations. During suspension operations, the well blew out, an explosion occurred on the *Deepwater Horizon* drilling rig, and the drilling rig sank, resulting in the release of hydrocarbons into the Gulf of Mexico. Eleven people lost their lives in the explosion and subsequent fire, and others sustained personal injuries. In September 2010, the Macondo well was permanently plugged. Refer to *Note 2—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 Drilling Moratorium and Other Related Matters

Anadarko ceased all drilling operations in the Gulf of Mexico in accordance with the deepwater drilling moratoria (collectively, the Moratorium), which resulted in the suspension of operations of two operated deepwater wells (Lucius and Nansen) and one non-operated deepwater well (Vito). The Moratorium was lifted October 12, 2010, but the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) has not approved new drilling permits. Anadarko is currently positioned to resume exploration and development drilling operations in the Gulf of Mexico, pending approvals of drilling permits and exploration and oil spill-response plans. See *Note 15—Contingencies—Deepwater Drilling Moratorium and Other Related Matters* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on the Moratorium.

United States Onshore

- The Company reallocated 7% of total 2010 budgeted capital expenditures from the Gulf of Mexico and redirected onshore United States capital expenditures to liquids-rich areas of the portfolio, including Eagleford, Bone Spring, Wattenberg and Greater Natural Buttes.
- The Company's Rocky Mountains Region (Rockies) achieved total-year sales volumes of 276 thousand barrels of oil equivalent per day (MBOE/d), representing an 11% increase over 2009.
- The Company's Southern and Appalachia Region achieved total-year sales volumes of 124 MBOE/d, representing a 7% increase over 2009.
- The Company entered into a joint-venture agreement that requires a third-party joint-venture partner to fund up to $1.5 billion of Anadarko's share of future acquisition, drilling, completion, equipment and other capital expenditures to earn a 32.5% interest in Anadarko's Marcellus shale assets, primarily located in north-central Pennsylvania.
- The Company acquired more than 80,000 net acres in the Maverick basin of southwest Texas for $93 million and increased its working interest in these properties to 75%.

Gulf of Mexico

- The Company's Gulf of Mexico total-year sales volumes were 155 MBOE/d, representing a 2% increase from 2009.
- The Company drilled successful sidetrack appraisal wells in the Gulf of Mexico at Lucius (50% working interest) and Vito (20% working interest).

International

- The Company drilled seven successful exploration wells with a 54% discovery rate. These wells included three in Mozambique, and one in each of Ghana, Indonesia, Sierra Leone and Brazil.
- The Company drilled five appraisal wells, four in Ghana and one in Brazil, with a 100% success rate.
- The Company and its partners took delivery and completed installation and commissioning of the floating production, storage and offloading vessel (FPSO) and achieved first oil at the Ghana Jubilee field in late 2010 on budget and 3.5 years following discovery.

Financial Highlights

Significant 2010 financial highlights include the following:

- Anadarko's income from continuing operations attributable to common stockholders for 2010 totaled $761 million compared to a loss of $135 million in 2009.
- The Company generated $5.2 billion of cash flows from operations compared to $3.9 billion in 2009 and ended the year with $3.7 billion of cash on hand.
- To manage its liquidity and the term structure of its debt, the Company raised $2.7 billion of cash in the public debt markets, and repaid $3.0 billion of aggregate principal amount of debt scheduled to mature in 2011 and 2012, reducing scheduled 2011 and 2012 debt maturities.
- The Company replaced its $1.3 billion revolving credit agreement scheduled to mature in 2013 with the $5.0 billion Facility maturing in 2015, which was undrawn at December 31, 2010.

The following discussion pertains to Anadarko's financial condition, results of operations and changes in financial condition. Unless noted otherwise, the following information relates to the continuing operations and any increases or decreases "for the year ended December 31, 2010" refer to the comparison of the year ended December 31, 2010, to the year ended December 31, 2009. Similarly, any increases or decreases "for the year ended December 31, 2009" refer to the comparison of the year ended December 31, 2009, to the year ended December 31, 2008. The primary factors that affect the Company's results of operations include, among other things, commodity prices for natural gas, crude oil and natural gas liquids (NGLs), sales volumes, the Company's ability to discover additional oil and natural-gas reserves, the cost of finding such reserves, and operating costs.

RESULTS OF CONTINUING OPERATIONS

Selected Data

millions except per-share amounts and percentages	**2010**	2009	2008
Financial Results			
Oil and condensate, natural-gas and NGLs sales	**$ 10,009**	$ 7,482	$ 12,997
Gathering, processing and marketing sales	**833**	728	1,082
Gains on divestitures and other, net	**142**	133	1,083
Reversal of accrual for DWRRA dispute	**—**	657	—
Total revenues and other	**10,984**	9,000	15,162
Costs and expenses	**9,215**	8,623	9,561
Other (income) expense	**128**	485	233
Income tax expense (benefit)	**820**	(5)	2,148
Income (loss) from continuing operations attributable to common stockholders	**$ 761**	$ (135)	$ 3,197
Income (loss) from continuing operations per common share attributable to common stockholders—diluted	**$ 1.52**	$ (0.28)	$ 6.78
Average number of common shares outstanding—diluted	**497**	480	466
Operating Results			
Adjusted EBITDAX*	**$ 7,226**	$ 6,033	$ 9,941
Total proved reserves (MMBOE)	**2,422**	2,304	2,277
Annual sales volumes (MMBOE)	**235**	220	206
Capital Resources and Liquidity			
Cash provided by operating activities	**$ 5,247**	$ 3,926	$ 6,447
Capital expenditures	**5,169**	4,558	4,881
Total debt	**13,013**	12,748	12,339
Stockholders' equity	**$ 20,684**	$ 19,928	$ 18,795
Debt to total capitalization ratio	**38.6%**	39.0%	39.6%

MMBOE—millions of barrels of oil equivalent

* 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 a reconciliation of Adjusted EBITDAX to income (loss) from continuing operations before income taxes, which is presented in accordance with GAAP.

FINANCIAL RESULTS

Income (Loss) from Continuing Operations Attributable to Common Stockholders Anadarko's income from continuing operations attributable to common stockholders for 2010 totaled $761 million, or $1.52 per share (diluted), compared to a loss from continuing operations attributable to common stockholders for 2009 of $135 million, or $0.28 per share (diluted). Anadarko's income from continuing operations attributable to common stockholders in 2008 was $3.2 billion, or $6.78 per share (diluted).

Sales Revenues, Volumes and Prices

millions except percentages	2010	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
Natural-gas sales	$ **3,420**	17%	$ 2,924	(49)%	$ 5,770
Oil and condensate sales	**5,592**	39	4,022	(37)	6,425
Natural-gas liquids sales	**997**	86	536	(33)	802
Total	$ **10,009**	34	$ 7,482	(42)	$ 12,997

Anadarko's sales revenues for the year ended December 31, 2010, increased primarily due to higher commodity prices and increased production volumes, while sales revenues for the year ended December 31, 2009, decreased primarily due to lower commodity prices partially offset by higher production volumes, as follows:

millions	Natural Gas	Oil and Condensate	NGLs	Total
2008 sales revenues	$ 5,770	$ 6,425	$ 802	$ 12,997
Changes associated with sales volumes	454	155	154	763
Changes associated with prices	(3,300)	(2,558)	(420)	(6,278)
2009 sales revenues	$ 2,924	$ 4,022	$ 536	$ 7,482
Changes associated with sales volumes	**72**	**286**	**192**	**550**
Changes associated with prices	**424**	**1,284**	**269**	**1,977**
2010 sales revenues	**$ 3,420**	**$ 5,592**	**$ 997**	**$ 10,009**

The following table provides Anadarko's sales volumes for the years ended December 31, 2010, 2009 and 2008.

	2010	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
Barrels of Oil Equivalent (MMBOE except percentages)					
United States	**209**	7%	196	9%	179
International	**26**	7	24	(9)	27
Total	**235**	7	220	7	206
Barrels of Oil Equivalent per Day (MBOE/d except percentages)					
United States	**572**	7%	537	9%	489
International	**71**	7	67	(9)	74
Total	**643**	7	604	7	563

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 *Other (Income) Expense—(Gains) Losses on Commodity 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

	2010	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
United States					
Sales volumes—Bcf	**829**	2%	809	8%	750
MMcf/d	**2,272**	2	2,217	8	2,049
Price per Mcf	**$ 4.12**	14	$ 3.61	(53)	$ 7.69
Natural-gas sales revenues (millions)	**$ 3,420**	17	$ 2,924	(49)	$ 5,770

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

The Company's daily natural-gas sales volumes increased 55 MMcf/d for the year ended December 31, 2010, primarily due to increased production in the Rockies of 61 MMcf/d, resulting from increased drilling in Greater Natural Buttes and the Greater Green River basins, as well as increased production in the Southern and Appalachia Region of 12 MMcf/d, associated with increased drilling in the Maverick basin, Haynesville shale and Marcellus shale. Increased natural-gas sales volumes were partially offset by natural production declines in the Gulf of Mexico of 18 MMcf/d.

The Company's daily natural-gas sales volumes increased 168 MMcf/d for the year ended December 31, 2009, primarily due to increased production in the Rockies of 138 MMcf/d due to positive results from dewatering coalbed methane wells and higher production uptime due to favorable weather. An increase in production in the Gulf of Mexico of 54 MMcf/d related to favorable weather conditions as compared to hurricane-related downtime experienced during 2008. Also, runtime at Independence Hub increased during 2009 as compared to 2008 when export pipeline repair work resulted in downtime. These increases in natural-gas production were partially offset by a 24 MMcf/d decrease in the Southern and Appalachia Region resulting from natural production declines experienced while drilling programs were shifted from established fields to emerging shale plays.

The average natural-gas price Anadarko received increased for the year ended December 31, 2010, primarily due to an increase in demand. Anadarko's average natural-gas price decreased substantially for the year ended December 31, 2009, primarily because of higher year-over-year U.S. natural-gas production and storage volumes coupled with lower United States demand for natural gas, triggered by the economic downturn in the United States.

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

	2010	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
United States					
Sales volumes—MMBbls	**48**	7%	44	10%	40
MBbls/d	**130**	7	120	10	108
Price per barrel	**$ 74.96**	28	$ 58.56	(39)	$ 96.20
International					
Sales volumes—MMBbls	**26**	7	24	(9)	27
MBbls/d	**71**	7	67	(9)	74
Price per barrel	**$ 78.52**	33	$ 59.01	(38)	$ 95.83
Total					
Sales volumes—MMBbls	**74**	7	68	2	67
MBbls/d	**201**	7	187	2	182
Total price per barrel	**$ 76.22**	30	$ 58.72	(39)	$ 96.05
Oil and condensate sales revenues (millions)	**$ 5,592**	39	$ 4,022	(37)	$ 6,425

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

Anadarko's daily crude-oil and condensate sales volumes increased 14 MBbls/d for the year ended December 31, 2010. This increase was partially due to higher crude-oil sales volumes of 5 MBbls/d in the Gulf of Mexico as completion of repairs to third-party downstream infrastructure that was damaged during the 2008 hurricane season occurred during the third quarter of 2009. In addition, crude-oil sales volumes increased 4 MBbls/d in the Southern and Appalachia Region due to a shift in focus from drilling in dry-gas areas to drilling in liquids-rich areas and 3 MBbls/d in the Rockies due to a full year of production efficiencies related to an oil pipeline that was placed in service in mid-2009, as well as a shift in focus to liquids-rich areas. Also, Algerian crude-oil sales volumes increased 3 MBbls/d primarily due to the timing of cargo liftings.

Anadarko's daily crude-oil and condensate sales volumes increased 5 MBbls/d for the year ended December 31, 2009, primarily due to higher crude-oil sales volumes of 8 MBbls/d in the Gulf of Mexico and 3 MBbls/d in the Rockies. The increase in the Gulf of Mexico results from additional production that came online during the fourth quarter of 2008, and favorable weather conditions as compared to 2008, which was impacted by export pipeline repair work and hurricane-related disruptions. The increase in the Rockies relates to production efficiencies from an oil pipeline that was placed into service in mid-2009. These increases were offset by lower Algerian crude-oil sales volumes of 6 MBbls/d due to the timing of cargo liftings and variances in the Organization of Petroleum Exporting Countries (OPEC) quotas.

The average crude-oil price Anadarko received increased for the year ended December 31, 2010, as a result of increased global demand. Anadarko's average crude-oil price decreased for the year ended December 31, 2009, primarily due to increased spare OPEC production capacity coupled with decreased global demand, particularly in the United States, Europe and Japan as a result of the economic downturn.

Natural-Gas Liquids Sales Volumes, Average Prices and Revenues

	2010	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
United States					
Sales volumes—MMBbls	**23**	36%	17	20%	14
MBbls/d	**63**	36	47	20	39
Price per barrel	**$ 43.07**	37	$ 31.42	(44)	$ 56.11
Natural-gas liquids sales revenues (millions)	**$ 997**	86	$ 536	(33)	$ 802

NGLs sales represent revenues from the sale of products derived from the processing of Anadarko's natural-gas production. The Company's daily NGLs sales volumes increased 16 MBbls/d for the year ended December 31, 2010, primarily related to operations in the Rockies where natural-gas production increased, an additional natural-gas processing train was brought online late in the second quarter of 2009, and improved recoveries due to new processing agreements entered into late in 2009.

Anadarko's daily NGLs sales volumes increased 8 MBbls/d for the year ended December 31, 2009, primarily because of a new processing train placed in service during the second quarter of 2009 at the Chipeta natural-gas processing plant, increased natural-gas production in the Rockies, and improved recoveries in the Southern and Appalachia Region due to new processing agreements in the Ozona area.

The average NGLs price increased for the year ended December 31, 2010, primarily due to higher crude-oil prices and sustained global petrochemical demand. For the year ended December 31, 2009, average NGLs prices decreased primarily due to decreased global petrochemical demand as a result of the economic downturn.

Gathering, Processing and Marketing Margin

millions except percentages	2010	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
Gathering, processing and marketing sales	**$ 833**	14%	$ 728	(33)%	$ 1,082
Gathering, processing and marketing expenses	**615**	—	617	(23)	800
Margin	**$ 218**	96	$ 111	(61)	$ 282

For the year ended December 31, 2010, gathering, processing and marketing margin increased $107 million. The increase was primarily due to higher margins associated with natural-gas sales from inventory, an increase in processed NGLs volumes and higher NGLs prices, both of which increased margins under percent-of-proceeds and keep-whole contracts, partially offset by the absence of gas-processing margins associated with assets divested in 2009.

For the year ended December 31, 2009, gathering, processing and marketing margin decreased $171 million. The decrease was primarily due to lower market prices for natural gas, NGLs and condensate, which led to reduced gas processing margins, lower margins associated with firm transportation contracts due to price differentials between supply and market areas, and unrealized losses on derivatives related to gas-storage activity, which is seasonal in nature, in that the margin realized on the future sale of stored volumes covered by these derivative instruments is expected to more than offset the recorded unrealized losses. These amounts were partially offset by increases in crude-oil and NGLs marketing margins, which were largely attributable to inventory write-downs to market value that occurred in the fourth quarter of 2008.

Gains (Losses) on Divestitures and Other, net

Gains on divestitures in 2010 were $29 million and related primarily to the divestiture of onshore United States oil and gas properties. Proceeds from the sale of these properties were $70 million. Gains on divestitures in 2009 were $44 million, primarily related to the sale of oil and gas properties in Qatar. Proceeds from the sale of oil and gas properties and midstream properties in 2009 were $109 million and $67 million, respectively. Gains on divestitures in 2008 were $1.2 billion, primarily related to the divestiture of certain oil and gas properties in Brazil, onshore United States and the Gulf of Mexico. Proceeds from 2008 divestitures were $2.5 billion and were used to reduce debt.

In 2008, gains (losses) on divestitures and other, net include a net $82 million ($52 million after tax) reduction related to corrections resulting from the analysis of property records after the adoption of the successful efforts method of accounting. This net amount includes a reduction of $163 million related to 2007. Management concluded that this misstatement was not material relative to 2007 interim and annual results, or to the 2008 periods, and corrected the error in the first quarter of 2008.

Reversal of Accrual for DWRRA Dispute

In January 2006, the Department of the Interior (DOI) issued an order (the 2006 Order) to Kerr-McGee Oil and Gas Corporation (KMOG), a subsidiary of Kerr-McGee Corporation (Kerr-McGee), to pay oil and gas royalties and accrued interest on KMOG's deepwater Gulf of Mexico production associated with eight 1996, 1997 and 2000 leases, for which KMOG considered royalties to be suspended under the Deepwater Royalty Relief Act (DWRRA). KMOG successfully appealed the 2006 Order, and the DOI's petition for a writ of certiorari with the United States Supreme Court was denied on October 5, 2009.

Based on the U.S. Supreme Court's denial of the DOI's petition for review by the court, Anadarko reversed its $657 million accrued liability in the third quarter of 2009 for royalties on leases listed in the 2006 order, as well as on similar orders to pay issued in 2008 and 2009, and other deepwater Gulf of Mexico leases with similar price threshold provisions. In addition, the Company reversed its $78 million accrued liability for unpaid interest on these amounts in the third quarter of 2009. Effective October 1, 2009, royalties and interest are no longer being accrued for deepwater Gulf of Mexico leases that have royalties suspended under the DWRRA. For more information on the DWRRA dispute, see *Note 15—Contingencies—Deepwater Royalty Relief Act* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Costs and Expenses

millions except percentages	**2010**	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
Oil and gas operating	$ **830**	(3)%	$ 859	(17)%	$ 1,036
Oil and gas transportation and other	**816**	23	664	7	621
Exploration	**974**	(12)	1,107	(19)	1,369

For the year ended December 31, 2010, oil and gas operating expenses decreased primarily due to decreased workover costs of $28 million in the Gulf of Mexico as a result of the Moratorium and subsequent delays in obtaining permits. For the year ended December 31, 2009, oil and gas operating expenses decreased primarily as a result of cost savings programs initiated in response to the reduction in oil prices in 2008 and 2009. Cost savings were achieved through operating efficiencies, deferral of certain workovers and vendor negotiations. These cost savings were realized primarily through lower workover costs and surface maintenance costs of $48 million and $21 million, respectively. Additional reductions were due to lower production handling costs of $54 million, primarily in the Gulf of Mexico due to repair-related pipeline downtime. In 2011, the Company expects to maintain efforts to manage costs more efficiently through its knowledge transfer initiatives and supply chain management negotiations; however, oil and gas operating expense per BOE could increase. Additionally, the costs of doing business in the Gulf of Mexico could increase due to the permit-timing delays and compliance with heightened BOEMRE regulatory requirements.

For the year ended December 31, 2010, oil and gas transportation and other expenses increased due to higher gas gathering and transportation costs of $77 million and $45 million, primarily attributable to increased production in the Rockies and the Southern and Appalachia Region, respectively, and the expensing of $27 million of idle drilling rig lease payments and $19 million of rig termination fees incurred in 2010 related to deepwater drilling rigs in the Gulf of Mexico. See *Note 15—Contingencies—Deepwater Drilling Moratorium and Other Related Matters* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion regarding the Company's decision to invoke force majeure on certain drilling rigs in the Gulf of Mexico. Partially offsetting this increase in oil and gas transportation and other expenses was $29 million of drilling rig contract termination fees incurred in 2009 as a result of low 2009 commodity prices. For the year ended December 31, 2009, oil and gas transportation and other expenses increased due to incremental transportation fees paid on increasing volumes in the Rockies of $41 million, and $29 million of drilling rig contract termination fees discussed above. These increases were partially offset by a decline in surface owner fees in the Rockies of $21 million due to lower 2009 commodity prices.

Exploration expense decreased $133 million for the year ended December 31, 2010, primarily due to a $128 million decline in dry hole expense in the United States, lower termination costs of $15 million in various international locations, and other items, partially offset by higher dry hole expense of $26 million in various other international locations, including Brazil, Ghana and Mozambique. Exploration expense for 2010 includes $46 million related to the Macondo well. Exploration expense decreased by $262 million for the year ended December 31, 2009, primarily due to lower impairments of unproved properties of $205 million and lower geological and geophysical expense of $87 million. The decrease in impairments of unproved properties related primarily to Gulf of Mexico properties partially offset by an increase in unproved property impairments in China due to the drilling of an unsuccessful well with no additional exploration plans. The decrease in geological and geophysical expense was primarily related to seismic data which was acquired and expensed in 2008 for Mozambique and Indonesia.

millions except percentages	**2010**	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
General and administrative	**$ 982**	—%	$ 983	14%	$ 866
Depreciation, depletion and amortization	**3,714**	5	3,532	11	3,194
Other taxes	**1,068**	43	746	(49)	1,452
Impairments	**216**	88	115	(48)	223

For the year ended December 31, 2010, general and administrative (G&A) expense decreased due to lower bonus plan expense of $67 million, offset by higher legal and consulting fees of $56 million primarily due to costs associated with the Tronox Incorporated (Tronox) bankruptcy and the Deepwater Horizon events, and higher employee-related costs of $11 million. The Company expects insurance costs to increase in 2011 as a result of higher coverage and related rates resulting from the Deepwater Horizon events that will be in effect for the full year in 2011 versus only part of 2010. In addition, the Company expects employee costs to increase primarily due to increased pension costs associated with changes in discount rates as well as increased headcount. The Company also expects legal expenses to increase in 2011 primarily due to Deepwater Horizon litigation; however, legal expenses related to Tronox are expected to decrease in 2011. See *Legal Proceedings* under Item 3 of this Form 10-K. For the year ended December 31, 2009, G&A expense increased primarily due to bonus plan expense. The increase was primarily related to a supplemental bonus plan, the payment of which was triggered by the Company's total-shareholder-return performance relative to a group of peer companies. The performance resulted in significantly increased market value relative to the peer-group-average performance, and all non-officer employees qualified for prescribed payments under the plan.

For the year ended December 31, 2010, depreciation, depletion and amortization (DD&A) increased $182 million primarily due to a $209 million increase attributable to higher production volumes and $89 million associated with depleted fields in the Gulf of Mexico, partially offset by lower DD&A rates attributable to reserve increases in the Marcellus shale and the Maverick basin. For the year ended December 31, 2009, DD&A increased $338 million primarily due to a $237 million increase attributable to higher sales volumes and an $84 million increase attributable to higher DD&A rates that were driven by higher accumulated costs associated with acquiring, finding and developing oil and gas reserves.

For the year ended December 31, 2010, other taxes increased $322 million primarily due to higher commodity prices and volumes resulting in increased Algerian exceptional profits tax of $129 million, increased United States production and severance taxes of $118 million, and increased Chinese windfall profits tax of $44 million. In addition, higher assessed property values increased ad valorem taxes by $30 million. For the year ended December 31, 2009, other taxes decreased $706 million primarily due to lower commodity prices, which resulted in lower United States production and severance taxes of $343 million, lower Algerian exceptional profits tax of $269 million, lower Chinese windfall profits tax of $60 million, and lower ad valorem taxes of $32 million.

Impairments for the year ended December 31, 2010, included $145 million of oil and gas exploration and production operating segment properties located in the United States. The properties in the United States include $114 million related to a production platform that remains idle with no immediate plan for use, and for which a limited market currently exists. The platform was impaired to its estimated fair value of $25 million. Impairments for the year ended December 31, 2010, also included $61 million ($23 million net of tax) related to the Company's investment in Venezuelan assets that was impaired to its estimated fair value. The Company's remaining after-tax net investment in these Venezuelan assets is $70 million. Also, for 2010, impairments included $8 million of marketing operating segment impairments related to the impairment of firm transportation contracts and $2 million of midstream operating segment assets. Impairments for the year ended December 31, 2009, related to $86 million of marketing operating segment assets, $22 million of oil and gas exploration and production operating segment properties in the United States and $7 million of midstream operating segment assets. The marketing operating segment impairments related to the impairment of firm transportation contracts, caused by narrowing margins between areas connected by acquired pipelines, and LNG facility-site properties.

Other (Income) Expense

millions except percentages	**2010**	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
Interest Expense					
Current debt, long-term debt and other	**$ 856**	17%	$ 734	(4)%	$ 762
Midstream subsidiary note payable to a related party	**24**	(38)	39	(64)	109
(Gain) loss on early debt retirements and commitment termination	**103**	NM	(2)	88	(16)
Capitalized interest	**(128)**	(86)	(69)	44	(123)
Interest expense	**$ 855**	22	$ 702	(4)	$ 732

NM—not meaningful

Anadarko's interest expense increased for the year ended December 31, 2010, primarily due to the reversal of $78 million in 2009 for previously accrued interest expense related to the DWRRA dispute, $17 million of costs expensed in 2010 in connection with the termination of a contemplated but unexecuted term-loan facility, $12 million of amortized debt issuance costs associated with the $5.0 billion Facility, and $9 million of expensed unamortized debt issuance costs, the recognition of which was triggered by the retirement of the Midstream Subsidiary Note Payable to a Related Party due 2012 (Midstream Subsidiary Note). Also, for 2010, interest expense included losses on early retirements of debt of $86 million, resulting from the repurchase of $1.4 billion aggregate principal amount of senior notes during 2010. These increases were partially offset by increases in capitalized interest of $59 million due to higher construction-in-progress balances related to long-term capital projects. Future interest expense is expected to increase due to amortization of issuance costs related to the $5.0 billion Facility and capital lease obligations. Anadarko's interest expense decreased for the year ended December 31, 2009, primarily due to the reversal of $78 million of previously accrued interest expense related to the DWRRA dispute, lower interest expense of $70 million due to the partial retirement of the Midstream Subsidiary Note and lower interest expense of $60 million due to the retirement of $1.4 billion in aggregate principal amount of Floating-Rate Notes during 2009, partially offset by interest expense of $108 million on $2.0 billion of debt issued in 2009 and $14 million primarily related to 2008 gains on early debt retirements. Also, in 2009, capitalized interest decreased $54 million due to lower capitalized costs that qualified for interest capitalization. For additional information, see *Liquidity and Capital Resources—Uses of Cash—Debt Retirements and Repayments* and *Interest-Rate Risk* under Item 7A of this Form 10-K.

millions except percentages	2010	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
(Gains) Losses on Commodity Derivatives, net					
Realized (gains) losses					
Natural gas	**$ (513)**	85%	$ (277)	166%	$ (104)
Oil and condensate	**15**	(130)	(50)	111	443
Total realized (gains) losses	**(498)**	52	(327)	196	339
Unrealized (gains) losses					
Natural gas	**(353)**	180	444	NM	(380)
Oil and condensate	**(42)**	114	291	(156)	(520)
Total unrealized (gains) losses	**(395)**	154	735	(182)	(900)
Total (gains) losses on commodity derivatives, net	**$ (893)**	NM	$ 408	(173)	$ (561)

The Company utilizes commodity derivative instruments to manage the risk of a decrease in the market prices for its anticipated sales of natural gas and crude oil. The change in (gain) loss on commodity derivatives, net includes the impact of derivatives entered into or settled and price changes related to positions open at December 31 of each year. For additional information on (gains) losses on commodity derivatives, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

millions except percentages	2010	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
(Gains) Losses on Other Derivatives, net					
Realized (gains) losses—interest-rate derivatives and other	**$ —**	(100)%	$ (525)	NM	$ —
Unrealized (gains) losses—interest-rate derivatives and other	**285**	NM	(57)	NM	7
Total (gains) losses on other derivatives, net	**$ 285**	(149)	$ (582)	NM	$ 7

Anadarko enters into interest-rate swaps to fix or float interest rates on existing or anticipated indebtedness to manage exposure to interest-rate changes. In December 2008 and January 2009, Anadarko entered into interest-rate swap contracts as a fixed-rate payor to mitigate the cost of potential 2011 and 2012 debt issuances. During periods of declining ten- and thirty-year U.S. Treasury yields, the fair value of this swap portfolio declines, as was the case during the year ended December 31, 2010. Conversely, when ten- and thirty-year U.S. Treasury yields rise, the fair value of this swap portfolio increases, as occurred during the year ended December 31, 2009. In 2009, the Company revised its contract terms which increased the weighted-average interest rate of the Company's swap portfolio from approximately 3.25% to approximately 4.80%, resulting in a realized gain of $552 million. For additional information, see *Interest-Rate Risk* under Item 7A of this Form 10-K.

millions except percentages	2010	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
Other (Income) Expense, net					
Interest income	**$ (13)**	(32)%	$ (19)	(57)%	$ (44)
Other	**(106)**	NM	(24)	124	99
Total other (income) expense, net	**$ (119)**	177	$ (43)	178	$ 55

Under the terms of the Master Separation Agreement (together with all annexes, related agreements, and ancillary agreements to it, the MSA) entered into between Kerr-McGee and Tronox, a former wholly owned subsidiary of Kerr-McGee that held Kerr-McGee's chemical business, Kerr-McGee agreed to reimburse Tronox for 50% of certain qualifying environmental-remediation costs incurred and paid by Tronox and its subsidiaries before November 28, 2012, subject to certain limitations and conditions. The reimbursement obligation under the MSA was limited to a maximum aggregate reimbursement of $100 million. During 2010, the Company reversed its $95 million liability for this reimbursement obligation to other (income) expense, net as a result of the cancellation of the MSA by Tronox that occurred as part of Tronox's bankruptcy proceedings. See *Note 14—Commitments* and *Note 15—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8, and *Legal Proceedings* under Item 3 of this Form 10-K for further discussion of events related to Tronox and this obligation.

In addition, changes in foreign currency exchange rates lowered other income by $54 million (losses of $2 million in 2010 compared to gains of $52 million in 2009) for the year ended December 31, 2010, primarily attributable to cash held in escrow pending final determination of the Company's Brazilian tax liability attributable to its 2008 divestiture of the Peregrino field offshore Brazil.

For 2009, the increase in total other income was primarily related to changes in foreign currency exchange rates of $70 million due to cash held in escrow pending final determination of the Company's Brazilian tax liability attributable to its 2008 divestiture of the Peregrino field offshore Brazil.

Income Tax Expense

millions except percentages	2010	2009	2008
Income tax expense (benefit)	**$ 820**	$ (5)	$ 2,148
Effective tax rate	**50%**	5%	40%

The increase from the 35% statutory rate for the year ended December 31, 2010, is primarily attributable to the following:

- the accrual of the Algerian exceptional profits tax that is non-deductible for Algerian income tax purposes;
- U.S. tax on foreign income inclusions and distributions;
- foreign tax rate differential and valuation allowance; and
- the unfavorable resolution of uncertain tax positions.

These amounts were partially offset by the following:

- U.S. income tax impact from losses and restructuring of foreign operations; and
- the federal manufacturing deduction and other items.

The decrease from the 35% statutory rate for the year ended December 31, 2009, is primarily attributable to the following:

- the accrual of the Algerian exceptional profits tax;
- foreign tax rate differential and valuation allowance; and
- U.S. tax on foreign income inclusions and distributions.

These amounts were partially offset by the following:

- benefits associated with changes in uncertain tax positions;
- state income taxes, including a change in the state income tax rate expected to be in effect at the time the Company's deferred state income tax liability is expected to be settled or realized; and
- U.S. income tax impact from losses and restructuring of foreign operations and other items.

The increase from the 35% statutory rate for the year ended December 31, 2008, is primarily attributable to the following:

- the accrual of the Algerian exceptional profits tax;
- U.S. tax on foreign income inclusions and distributions; and
- state income taxes and other items.

For additional information on income tax rates, see *Note 17—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Net Income Attributable to Noncontrolling Interests

For the years ended December 31, 2010, 2009 and 2008, the Company's net income attributable to noncontrolling interests of $60 million, $32 million and $23 million, respectively, primarily related to the public ownership interests in Western Gas Partners, LP (WES), a consolidated subsidiary of the Company. Public ownership of WES was 51.5%, 43.2% and 36.7% at year-end 2010, 2009 and 2008, respectively. See *Note 7—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 operating results of Anadarko's segments, the chief operating decision maker analyzes income (loss) from continuing operations before income taxes, interest expense, exploration expense, DD&A, impairments, and unrealized (gains) losses on derivative instruments, net, less net income attributable to noncontrolling interests (Adjusted EBITDAX). Anadarko's definition of Adjusted EBITDAX, which is not a GAAP measure, excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. The Company's definition of Adjusted EBITDAX also excludes exploration expense, as exploration expense 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. In addition, unrealized (gains) losses on derivative instruments, net are excluded from Adjusted EBITDAX since these unrealized (gains) losses are not considered to be a measure of asset-operating performance. 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 flow 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) from continuing operations before income taxes.

Adjusted EBITDAX

millions except percentages	**2010**	Inc/(Dec) vs. 2009	2009	Inc/(Dec) vs. 2008	2008
Income (loss) from continuing operations before income taxes	**$ 1,641**	NM	$ (108)	(102)%	$ 5,368
Exploration expense	**974**	(12)%	1,107	(19)	1,369
DD&A	**3,714**	5	3,532	11	3,194
Impairments	**216**	88	115	(48)	223
Interest expense	**855**	22	702	(4)	732
Unrealized (gains) losses on derivative instruments, net*	**(114)**	(116)	717	178	(922)
Less: Net income attributable to noncontrolling interests	**60**	88	32	39	23
Consolidated Adjusted EBITDAX	**$ 7,226**	20	$ 6,033	(39)	$ 9,941
Adjusted EBITDAX by segment					
Oil and gas exploration and production	**$ 6,689**	22	$ 5,463	(47)	$ 10,332
Midstream	**387**	19	324	(24)	428
Marketing	**7**	106	(110)	NM	34
Other and intersegment eliminations	**143**	(60)	356	142	(853)

* In the fourth quarter of 2010, the Company revised the definition of Adjusted EBITDAX to exclude the impact of unrealized (gains) losses on derivative instruments, net. All prior periods have been adjusted to reflect this change.

Oil and Gas Exploration and Production The increase in Adjusted EBITDAX for the year ended December 31, 2010, was primarily due to the impact of higher commodity prices and higher sales volumes, partially offset by the 2009 reversal of amounts previously accrued in connection with the DWRRA dispute. The decrease in Adjusted EBITDAX for the year ended December 31, 2009, was primarily due to the impact of lower commodity prices, partially offset by higher natural-gas sales volumes primarily in the Rockies and the reversal of amounts previously accrued in connection with the DWRRA dispute.

Midstream The increase in Adjusted EBITDAX for the year ended December 31, 2010 resulted primarily from an increase in revenue due to higher prices and NGLs volumes which impacted revenues earned under the Company's percent-of-proceeds and keep-whole contracts, partially offset by higher cost of product related to NGLs purchases which increased due to higher NGLs prices, and margins associated with assets divested in 2009. The decrease in Adjusted EBITDAX for the year ended December 31, 2009, resulted primarily from a decrease in revenue due to lower prices for natural gas, NGLs and condensate, which impacted revenues earned under the Company's percent-of-proceeds and keep-whole contracts, partially offset by lower cost of product due to lower natural-gas and NGLs prices.

Marketing Marketing earnings primarily represent the margin earned on sales of natural gas, oil and NGLs purchased from third parties. The increase in Adjusted EBITDAX for the year ended December 31, 2010, was primarily due to higher margins associated with natural-gas sales from inventory, and lower transportation costs due to lower firm transportation amortization as a result of asset impairments in 2009. The increase in Adjusted EBITDAX for the year ended December 31, 2009, was primarily due to a decrease of approximately 30% in marketed third-party volumes, and lower margins associated with firm transportation contracts due to price differentials between supply and market areas. These amounts were partially offset by higher crude-oil marketing margins, and higher NGLs marketing margins primarily due to inventory write-downs to market value taken in the fourth quarter of 2008.

Other and Intersegment Eliminations Other and intersegment eliminations consists primarily of corporate costs, realized gains and losses on derivatives and income from hard minerals investments and royalties. The decrease in Adjusted EBITDAX for the year ended December 31, 2010, was primarily due to realized gains on interest-rate swaps in 2009 partially offset by increased realized gains on commodity derivatives in 2010 and the reversal of the $95 million liability related to the reimbursement obligation that was provided by Kerr-McGee to Tronox pursuant to the terms of the MSA. The increase in Adjusted EBITDAX for the year ended December 31, 2009, was primarily due to realized gains on interest-rate swaps in 2009 and increased realized gains on commodity derivatives in 2009.

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

Additional reserve 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	**2010**	2009	2008
Proved Reserves*			
Beginning of year	**2,304**	2,277	2,431
Reserve additions and revisions	**359**	275	188
Sales in place	**(6)**	(24)	(137)
Production	**(235)**	(224)	(205)
End of year	**2,422**	2,304	2,277
Proved Developed Reserves*			
Beginning of year	**1,624**	1,600	1,625
End of year	**1,673**	1,624	1,600

* As required by the Securities and Exchange Commission, reserves for 2010 and 2009 are computed using the 12-month average beginning-of-month prices, and reserves for 2008 are computed using year-end prices.

Reserve Additions and Revisions During 2010, the Company added 359 MMBOE of proved reserves as a result of additions (purchases in place, discoveries and extensions) and revisions. The Company expects the majority of future reserve growth to come from positive revisions associated with infill drilling and extensions of current fields and new discoveries onshore United States and the deep waters of the Gulf of Mexico, as well as through purchases of proved properties in strategic areas and successful exploration in international growth areas. The success of these operations will directly impact reserve additions or revisions in the future.

Additions During 2010, Anadarko added 83 MMBOE of proved reserves primarily as a result of successful drilling in the United States. Although shale plays only represent about 2% of the Company's total proved reserves, growth in the Company's shale plays contributed 45 MMBOE of the total additions. The Company also acquired 1 MMBOE of proved reserves in place related to onshore domestic assets in 2010. During 2009, Anadarko added 70 MMBOE of proved reserves primarily as a result of successful drilling in the United States and international locations. The Company also acquired 32 MMBOE of proved reserves in place related to onshore domestic assets in 2009. During 2008, Anadarko added 96 MMBOE of proved reserves primarily as a result of successful drilling, and development and appraisal wells in the United States.

Revisions Total revisions in 2010 were 275 MMBOE or 12% of the beginning-of-year reserve base. The revisions included an increase of 312 MMBOE primarily related to successful infill drilling in large onshore natural-gas plays, such as the Greater Natural Buttes, Wattenberg and Pinedale fields (where the reserve bookings for the infill wells are treated as positive revisions), 77 MMBOE of revisions to prior estimates and 29 MMBOE associated with higher oil and gas prices. These positive revisions were partially offset by the transfer of 143 MMBOE of PUDs to unproved categories as a result of changes to development plans during 2010. Total revisions in 2009 were 173 MMBOE or 8% of the beginning-of-year reserve base. The revisions included an increase of 212 MMBOE primarily related to large onshore natural-gas plays, such as the Greater Natural Buttes and Pinedale fields, as a result of successful infill drilling (where the reserve bookings for the infill wells are treated as positive revisions). The revisions also include a decrease of 39 MMBOE caused by lower natural-gas prices. Total revisions in 2008 were 92 MMBOE or 4% of the beginning-of-year reserve base. The revisions included an increase of 194 MMBOE primarily related to Greater Natural Buttes, Wattenberg and Pinedale fields, as a result of successful infill drilling, and positive revisions to the Peregrino heavy-oil field, offshore Brazil, which was sold in 2008, partially offset by a decrease of 102 MMBOE related to price impacts for oil and NGLs.

Sales in Place During 2010, the Company sold properties located in the United States and Egypt representing 5 MMBOE of proved developed reserves and 1 MMBOE of proved undeveloped reserves. In 2009, the Company sold properties located onshore United States representing 24 MMBOE of proved reserves. These properties were primarily in the Rockies and represented 14 MMBOE of developed properties and 10 MMBOE of undeveloped properties. In 2008, the Company sold properties located onshore United States and Brazil. The properties located in the United States represented 46 MMBOE of proved reserves with 31 MMBOE developed and 15 MMBOE undeveloped. The properties located in Brazil represented 91 MMBOE of proved undeveloped reserves.

Discounted Future Net Cash Flows At December 31, 2010, the discounted (at 10%) estimated future net cash flows from Anadarko's proved reserves was $21.5 billion (stated in accordance with the regulations of the Securities and Exchange Commission (SEC) and the Financial Accounting Standards Board (FASB)). These discounted future net cash flows were 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. For reporting periods prior to December 31, 2009, year-end prices were used for calculating discounted future net cash flows. The increase of $7.9 billion or 58% in 2010 compared to 2009 is primarily due to changes in prices and costs as well as revisions of previous quantity estimates. See *Supplemental Information* under Item 8 of this Form 10-K.

The present value of future net cash flows does not purport to be an estimate of the fair value of Anadarko's proved reserves. A fair-value estimate 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 gas.

LIQUIDITY AND CAPITAL RESOURCES

Overview Anadarko generates its capital needed over the long term to fund capital expenditures, debt-service obligations, and dividend payments primarily from cash flows from operating activities, and enters into debt and equity transactions to maintain the desired capital structure and finance acquisition opportunities. Liquidity may also be enhanced through asset divestitures and joint ventures that reduce future capital expenditures.

Consistent with this approach, during 2010, cash flows from operating activities were the primary source for funding capital investment, while proceeds from issuing debt were used to refinance existing debt obligations. 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 both current and expected future conditions.

During 2010, the Company further enhanced its liquidity in response to the potential exposure to future obligations related to the Deepwater Horizon events by refinancing $3.0 billion of its 2011 and 2012 scheduled maturities with longer-term debt and replacing its $1.3 billion revolving credit facility scheduled to mature in 2013 with the $5.0 billion Facility maturing in 2015, thereby significantly increasing the Company's capacity for immediate access to capital. Entering into the $5.0 billion Facility, coupled with certain modifications to contracts governing the Company's commodity derivative arrangements, also reduced the Company's potential obligation to provide cash collateral, as discussed under *Effects of Credit Rating Downgrade* below.

At December 31, 2010, Anadarko's 2011 and 2012 scheduled debt maturities were $289 million and $223 million, respectively, for a total of $512 million (including repayments of WES's senior unsecured revolving credit facility (RCF) and the Company's capital lease obligations), or $1.2 billion including the accreted value of Zero-Coupon Senior Notes (Zero Coupons) that could be put to the Company in 2012, as discussed below. The Company has a variety of funding sources available, including cash on hand of $3.7 billion at December 31, 2010, an asset portfolio that provides ongoing cash-flow-generating capacity and opportunities for liquidity enhancement through divestitures and joint-venture arrangements. In addition, the Company's $5.0 billion Facility remains undrawn at December 31, 2010, providing available capacity of $4.6 billion ($5.0 billion undrawn capacity less $377 million of outstanding letters of credit supported by the $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 current operations and, based on information currently available, any potential future obligations related to the Deepwater Horizon events. However, Anadarko is currently unable to predict the ultimate impact of the Deepwater Horizon events on the Company's liquidity and financial condition. See *Note 2—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Revolving Credit Facility Borrowings under the $5.0 billion Facility will bear interest, at the Company's election, at (i) the London Interbank Offered Rate (LIBOR) plus a margin ranging from 2.75% to 3.75%, based on the Company's credit rating, or (ii) the greatest of (a) the JPMorgan Chase Bank prime rate, (b) the federal funds rate plus 0.50%, or (c) one-month LIBOR plus 1%, plus in each case, an applicable margin.

Obligations incurred under the $5.0 billion Facility, as well as obligations Anadarko may have to certain lenders or their affiliates pursuant to certain derivative instruments as discussed in *Note 9—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.

The Company incurred upfront underwriting, structuring, arrangement and other costs in connection with the $5.0 billion Facility. These costs were capitalized and will be amortized over the five-year credit commitment term. The cost of capital to the Company under the terms of the $5.0 billion Facility is greater than the cost of capital to the Company under the $1.3 billion revolving credit agreement previously in effect due to the increased size and term of the $5.0 billion Facility and then-current market conditions. For example, outstanding borrowings under the $5.0 billion Facility at December 31, 2010, would bear a LIBOR-based interest-rate margin of 2.75% as compared to a margin of 0.55% provided for under the $1.3 billion credit agreement previously in effect. Costs ultimately incurred under the $5.0 billion Facility will vary with the level of facility utilization, the ultimate borrowing terms and Anadarko's corporate credit rating.

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. The Company was in compliance with all applicable covenants at December 31, 2010, and there were no restrictions on its ability to utilize the available capacity of the $5.0 billion Facility.

At December 31, 2010, the covenants contained in certain of the Company's credit agreements provided for a maximum 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 in order to ensure covenant compliance. At December 31, 2010, 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 maturing October 2036. The Zero Coupons have an aggregate principal amount due at maturity of $2.4 billion, reflecting a yield to maturity of 5.24%. The holder has the right to cause the Company to repay up to 100% of the then-accreted value of the Zero Coupons in October of each year starting in 2012. The accreted value of the Zero Coupons is $607 million at December 31, 2010 and will be $682 million at the next possible put date in October 2012.

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 Zero Coupons if the put option is exercised by the holder.

Effects of Credit Rating Downgrade As a consequence of uncertainties regarding the possible range of Anadarko's potential obligations related to the Deepwater Horizon events, in June 2010, Moody's lowered the Company's senior unsecured credit rating from "Baa3" to "Ba1" and placed the Company's long-term ratings under review for further possible downgrade (the credit rating downgrade), while S&P and Fitch each affirmed their "BBB-" rating with a negative outlook. In September 2010, Moody's announced that it concluded its review and confirmed Anadarko's "Ba1" credit rating and changed the rating outlook to stable.

As a result of the credit rating downgrade in June 2010, the Company's credit thresholds with its derivative counterparties were reduced and in many cases eliminated, which would ordinarily increase the possibility that counterparties could require additional collateral when the Company's net derivative trading position is a liability. However, because certain of the Company's derivative counterparties are also lenders under the $5.0 billion Facility, and as such, receive security interests in specified assets of the Company, derivative-related agreements with most of these counterparties have been amended such that those counterparties require no additional collateral beyond that provided under the $5.0 billion Facility. As a result, at December 31, 2010, the Company had only $15 million of cash collateral provided as security for its derivative-contract-related obligations (compared to $105 million at December 31, 2009), and expects such future cash requirements to be relatively insignificant.

The credit rating downgrade also increases the likelihood of Anadarko being required to post collateral as financial assurance of its performance under other contractual arrangements, such as pipeline transportation contracts, oil and gas sales contracts and work commitments. At December 31, 2010, $461 million of letters of credit ($377 million of which were supported by the $5.0 billion Facility) were provided as assurance of the Company's performance under various contractual arrangements and commitments, compared to $339 million at December 31, 2009.

WES Funding Sources Anadarko's consolidated subsidiary, WES, primarily uses cash to fund its ongoing operations, make acquisitions and other capital investments, service its debt, and make distributions to equity holders. WES relies primarily on cash generated from its operating activities for funding, as well as debt or equity issuances, supplemented as needed with borrowings under its revolving credit facility. WES has committed borrowing capacity of $450 million under its RCF that extends through October 2012. The RCF is not guaranteed by Anadarko or any of its wholly owned subsidiaries. Outstanding borrowings under the RCF, which bear interest at LIBOR plus an applicable margin ranging from 2.375% to 3.250% (for a rate of 3.26% at December 31, 2010), were $49 million at December 31, 2010, with $401 million remaining borrowing capacity. The credit rating downgrade of Anadarko did not affect the availability of credit or the cost of borrowing under the WES RCF.

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 well, restoration and redrill, sudden and accidental pollution, third-party liability, workers' compensation and employers' liability, and other risks. The below-stated insurance limits for blowout/control of well and for third-party liabilities are reduced proportionally to Anadarko's participating interest in a venture. Some of the below-stated limits are aggregate amounts, but most policies allow for reinstatement. Anadarko's insurance coverage includes deductibles which 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 from all potential consequences and damages.

Anadarko's property and casualty insurance policies renew in June of each year, with the next renewals scheduled for June 2011. In light of the Deepwater Horizon events, the Company may not be able to secure similar coverage for the same costs, if at all. Future insurance coverage for the oil and gas industry could increase in cost 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. Refer to *Note 2—Deepwater Horizon Events—Insurance Recoveries* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of the Company's insurance coverage applicable to the Deepwater Horizon events.

The Company's current insurance coverage, which was obtained subsequent to the Deepwater Horizon events, includes physical damage to Anadarko's properties on a replacement cost basis; $500 million in limit for loss of production income for the Independence Hub facility; $500 million for an offshore blowout/control of a well, restoration and redrill, and pollution from an offshore blowout ($75 million for onshore); $275 million aircraft liability; and $675 million in limit for third-party liabilities. The Company's total limit is approximately $1.2 billion (which is reduced proportionally to the Company's participating interest in a venture) for the negative environmental impacts of an offshore blowout. If caused by a named windstorm, there is currently no coverage for physical damage to the Company's properties, loss of production income for the Independence Hub facility, blowout/control of a well, or restoration and redrill.

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, 2010. 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 flow from operating activities in 2010 was $5.2 billion compared to $3.9 billion in 2009 and $6.4 billion in 2008. The increase in cash flow from continuing operations for the year ended December 31, 2010, was primarily attributable to higher commodity prices, higher sales volumes and the impact of changes in working capital items.

The decrease in cash flow from continuing operations for the year ended December 31, 2009, was primarily attributable to lower commodity prices, partially offset by higher sales volumes and realized gains on interest-rate derivatives that resulted from the Company's election to revise the contractual terms of its interest-rate swap portfolio which resulted in the realization of $552 million in cash.

Fluctuations in commodity prices are one of the primary sources of variability in the Company's cash flows from operating activities, which Anadarko manages by entering into commodity derivative instruments. 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, the amount of costs and expenses required for continued operations and debt service, as well as any potential obligation to fund Deepwater Horizon event-related liabilities. Refer to *Note 2—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.

Investing Activities During 2010, 2009 and 2008, Anadarko received proceeds of $70 million, $176 million and $2.5 billion before income taxes, respectively, related to several property divestiture transactions. Proceeds received in 2008 relate to the divestiture and portfolio rationalization activity initiated following Anadarko's corporate acquisitions completed in August 2006. In connection with the retirement of the Midstream Subsidiary Note and the associated liquidation of Trinity Associates LLC (Trinity) in 2010, Anadarko received $100 million in cash representing the return of the Company's original investment in Trinity.

Financing Activities During 2010, the Company received net proceeds of $2.7 billion related to the issuance of $2.8 billion in aggregate principal amount of senior notes and used the net proceeds, combined with cash on hand, to redeem $3.0 billion aggregate principal amount of 2011 and 2012 debt maturities. See *Uses of Cash* for further information about debt repayments.

As discussed in *Revolving Credit Facility* above, Anadarko entered into the $5.0 billion Facility in 2010. In connection with the $5.0 billion Facility, the Company incurred upfront underwriting, structuring, arrangement and other costs totaling $172 million. No borrowings were made under the $5.0 billion Facility upon closing and through the date of filing this Form 10-K.

During 2010, Anadarko's consolidated subsidiary, WES, borrowed a total of $670 million under a three-year senior unsecured term loan (the Term Loan) and RCF primarily to fund the acquisition of certain midstream assets from Anadarko. During 2010, WES issued approximately 13 million common units in two public offerings, realizing net proceeds of $338 million, which were used to repay a portion of outstanding RCF borrowings.

During 2009, Anadarko raised $2.0 billion in connection with the public offering of senior notes and an additional $1.3 billion in connection with the public offering of 30 million shares of common stock. Proceeds from the offerings were used to fund the retirement of outstanding Floating Rate Notes and for general corporate purposes.

During 2008, $321 million was raised in connection with the initial public offering of 20.8 million common units of its consolidated affiliate, WES. See *Note 7—Noncontrolling Interest* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. Proceeds from the offering were used to reduce debt.

Uses of Cash

In addition to ongoing funding of operating costs and expenses, including interest cost and taxes, Anadarko invests significant capital to acquire, explore and develop oil and natural-gas resources and midstream infrastructure, and makes debt repayments.

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

millions	**2010**	2009	2008
Property Acquisitions			
Exploration	**$ 519**	$ 279	$ 405
Development	**22**	266	26
Exploration	**1,278**	1,229	1,031
Development	**3,267**	2,886	3,530
Total oil and gas costs incurred*	**5,086**	4,660	4,992
Less: Corporate acquisitions and non-cash property exchanges	**(37)**	(284)	(106)
Less: Asset retirement costs	**(86)**	(63)	(263)
Less: Geological and geophysical, exploration overhead, delay rentals expenses and other expenses	**(291)**	(312)	(344)
Less: Amortization of acquired drilling rig contract intangibles	**—**	—	(5)
Total oil and gas capital expenditures	**4,672**	4,001	4,274
Gathering, processing and marketing and other	**497**	557	607
Total capital expenditures*	**$ 5,169**	$ 4,558	$ 4,881

* 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 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.

Anadarko's capital spending increased 13% for the year ended December 31, 2010, primarily due to an increase in exploration lease acquisitions onshore and offshore United States, higher development drilling onshore and increased expenditures related to construction in Algeria. During 2010, the Company reallocated 7% of its total 2010 budgeted capital expenditures from the Gulf of Mexico and redirected onshore United States capital expenditures to focus on liquids-rich areas onshore United States. The Company spent approximately $200 million less than the original budgeted capital expenditures. During the first quarter of 2010, the Company entered into a joint-venture agreement that requires a third-party joint-venture partner to fund up to $1.5 billion of Anadarko's share of future acquisition, drilling, completion, equipment and other capital expenditures to earn a 32.5% interest in Anadarko's Marcellus shale assets, primarily located in north-central Pennsylvania. At December 31, 2010, $394 million of the total $1.5 billion obligation had been funded.

Anadarko's capital expenditures decreased 7% for the year ended December 31, 2009 primarily due to declines in development drilling expenditures onshore United States and expenditures on gathering and processing facilities. These declines were partially offset by an increase in development drilling expenditures in Ghana, exploration drilling expenditures onshore United States, property acquisition costs and capital expenditures related to the Company's acquisition of office buildings in The Woodlands, Texas. Property acquisitions in 2009 primarily related to exploratory non-producing leases onshore United States and proved property acquisitions related to property exchanges in the Rockies. Property acquisitions in 2008 primarily related to exploratory non-producing leases.

See *Outlook* below for information regarding sources of cash used to fund capital expenditures for 2011.

Debt Retirements and Repayments In 2010, the Company used $1.6 billion to repay the Midstream Subsidiary Note and $1.5 billion, including $86 million for early-tender premiums, to redeem senior notes scheduled to mature in 2011 and 2012. The repayments were funded with proceeds from new borrowings, as well as cash on hand. Also in 2010, WES repaid $371 million outstanding under its RCF primarily from proceeds related to its public offerings discussed in *Sources of Cash*.

In 2009, using a portion of proceeds from new debt issuances, the Company repaid an aggregate principal amount of $1.6 billion of debt that was outstanding at December 31, 2008, including $1.4 billion in aggregate principal amount of Floating-Rate Notes due in 2009. In 2008, Anadarko repaid an aggregate principal amount of $2.4 billion of outstanding debt including the remaining balance of the variable-rate 354-day facility originally used to fund corporate acquisitions, and $580 million in aggregate principal amount of Floating-Rate Notes due September 2009. The debt repayments were funded primarily by operating cash flow and proceeds from asset divestitures.

For additional information on the Company's debt instruments, such as transactions during the period, years of maturity and interest rates, see *Note 9—Derivative Instruments* and *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Common Stock Repurchase Program In August 2008, the Company initiated a $5 billion share-repurchase program under which shares may be repurchased either in the open market or through privately negotiated transactions. The program is authorized to extend through August 2011. The program does not obligate Anadarko to acquire any specific number of shares and may be discontinued at any time. During 2008, Anadarko purchased 10 million shares of common stock for $600 million under the program through purchases in the open market and under share-repurchase agreements. No shares were repurchased under the program in 2009 or 2010.

Common Stock Dividends and Distributions to Noncontrolling WES Interest Owners In 2010, 2009 and 2008, Anadarko paid $180 million, $176 million and $170 million, respectively, in dividends to its common stockholders (nine cents per share per quarter). Anadarko has paid a dividend to its common stockholders quarterly since becoming an independent public company in 1986. The amount of future dividends for Anadarko common stock will depend on earnings, financial conditions, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants contained in its debt agreements and other factors, and will be determined by the Board of Directors on a quarterly basis.

Anadarko's consolidated subsidiary, WES, distributed to its unitholders other than Anadarko an aggregate of $42 million, $26 million and $10 million during 2010, 2009 and 2008, respectively. WES has made quarterly distributions to its unitholders since its initial public offering in the second quarter of 2008 and has increased its distribution from $0.33 per common unit for the fourth quarter of 2009 to $0.38 per common unit for the fourth quarter of 2010.

Outlook

The Company remains committed to the execution of its worldwide exploration, appraisal and development programs. The Company plans to allocate approximately 60% of its 2011 capital spending to development activities, 25% to exploration activities and 15% to gas-gathering and processing activities and other business activities. The Company expects its 2011 capital spending by area to be approximately 50% for the United States onshore region and Alaska, 10% for the Gulf of Mexico, 25% for International and 15% for Midstream and other.

Anadarko believes that its expected level of operating cash flows and cash on hand at December 31, 2010, will be sufficient to fund the Company's projected operational and capital programs for 2011, while continuing to meet its other obligations. However, if capital expenditures exceed operating cash flows and cash on hand, additional funding would likely be supplemented as needed through short-term borrowings under the $5.0 billion Facility, which remains undrawn at December 31, 2010 and provides available capacity of $4.6 billion ($5.0 billion undrawn capacity less $377 million of outstanding letters of credit supported by the $5.0 billion Facility), as well as asset divestitures and joint-venture arrangements. 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 both current and expected future conditions. In order to increase the predictability of 2011 cash flows, Anadarko has entered into strategic derivative positions, which, at December 31, 2010, cover approximately 25% and 57% of its anticipated natural-gas sales volumes and oil and condensate sales volumes, respectively, for 2011. In addition, the Company has commodity derivative positions in place for 2012. See *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

The Company's primary emphasis is on managing near-term growth opportunities with a commitment to worldwide exploration and the continued development of large oil projects in Algeria, offshore Ghana and in the deepwater Gulf of Mexico. In response to the Deepwater Horizon events, the federal government may issue further safety and environmental laws or regulations regarding operations in the Gulf of Mexico, in addition to the regulations promulgated by the BOEMRE during 2010, which are described in greater detail in the *Risk Factors* under Item 1A of this Form 10-K. These additional laws and regulations, delays in the processing and approval of drilling permits and exploration and oil spill-response plans as well as possible additional actions could affect the timing of new drilling and ongoing development efforts, result in increased costs, and limit activities in certain areas of the Gulf of Mexico.

Off-Balance Sheet Arrangements

Anadarko may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At December 31, 2010, the Company's material off-balance sheet arrangements and transactions include operating lease arrangements and undrawn letters of credit. 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. See *Obligations and Commitments* for more information regarding off-balance sheet arrangements.

Obligations and Commitments

The following is a summary of the Company's obligations at December 31, 2010.

	Obligations by Period				
millions	1 Year	2-3 Years	4-5 Years	More than 5 Years	Total
Total debt					
Principal—current borrowings	$ 285	$ —	$ —	$ —	$ 285
Principal—long-term borrowings [1]	—	469	775	13,007	14,251
Principal—capital lease obligations [2]	4	9	12	201	226
Investee entities' debt [3]	—	—	—	2,853	2,853
Interest on borrowings	845	1,634	1,519	8,697	12,695
Interest on capital lease obligations [2]	33	66	63	260	422
Investee entities' interest [3]	44	153	266	4,321	4,784
Operating leases					
Drilling rig commitments	574	795	—	—	1,369
Production platforms	61	90	107	204	462
Other	92	120	58	34	304
Asset retirement obligations	42	470	118	941	1,571
Midstream and marketing activities	282	540	403	666	1,891
Oil and gas activities	880	726	81	394	2,081
Derivative liabilities [4]	42	56	—	165	263
Uncertain tax positions, interest and penalties [5]	24	34	—	—	58
Environmental liabilities	19	22	12	43	96
Total [6]	$ 3,227	$ 5,184	$ 3,414	$ 31,786	$ 43,611

(1) This table presents the fully accreted principal amount of the Zero Coupons of $2.4 billion as coming due after 2015. While the Zero Coupons do not mature until 2036, the holder has the right to put the Zero Coupons to the Company each October beginning in 2012 at their then-accreted value. The Company could be required to repurchase 100% of the Zero Coupons at $682 million in October 2012.

(2) See *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for capital lease obligations.

(3) 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 and included 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 8—Investments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(4) Represents Anadarko's gross derivative liability after taking into account the impacts of netting margin and collateral balances deposited with counterparties. See *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(5) See *Note 17—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(6) This table does not include the Company's pension or postretirement benefit obligations. See *Note 20—Pension Plans, Other Postretirement Benefits and Defined-Contribution Plans* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Operating Leases Operating lease obligations include several deepwater drilling rig commitments totaling $1.4 billion. Anadarko continues to manage its access to rigs in order to execute its worldwide deepwater drilling strategy over the next several years. Lease payments associated with successful exploratory wells and development wells, net of amounts billed to partners, are capitalized as a component of oil and gas properties. See *Note 15—Contingencies—Deepwater Drilling Moratorium and Other Related Matters* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on drilling rigs.

The Company has $766 million in commitments under noncancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors and aircraft.

For additional information, see *Note 14—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 transportation, storage and purchase agreements in order to access markets and provide flexibility for the sale of its natural gas and crude oil in certain areas.

Oil and Gas Activities Anadarko has various long-term contractual commitments pertaining to exploration, development and production activities that extend beyond 2010. 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 $2,081 million, comprised of $1,433 million related to the United States and $648 million 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, 2010, the Company's balance sheet included a $96 million liability for remediation and reclamation obligations, most of which relate to companies acquired by Anadarko. The Company continually monitors the liability recorded and the remediation and reclamation process, and believes the amount recorded is appropriate. For additional information on environmental issues, see *Risk Factors* under Item 1A of this Form 10-K.

For additional information on contracts, obligations and arrangements the Company enters into from time to time, see *Note 9—Derivative Instruments, Note 11—Debt and Interest Expense, Note 14—Commitments,* and *Note 15—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Discontinued Operations

In November 2006, Anadarko sold its wholly owned subsidiary, Anadarko Canada Corporation. The results of Anadarko's Canadian operations have been classified as discontinued operations in the Consolidated Statements of Income and Consolidated Statements of Cash Flows for 2008 and primarily relate to adjustments to an indemnity obligation provided by the Company to the purchaser, as well as expenses associated with finalizing exit activities. See *Note 15—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

In preparing financial statements in accordance with GAAP, management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Management reviews its estimates and related assumptions regularly, including those related to the value of properties and equipment, proved reserves, goodwill, intangible assets, asset retirement obligations, litigation reserves, environmental liabilities, pension assets and 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 and discusses the selection and development of these estimates 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. 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 assessed for impairment during the holding period and 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.

For unproved oil and gas properties with individually insignificant lease acquisition costs, 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.

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 had limited or no previous exploratory drilling are generally assessed for impairment by major prospect area.

A majority of the Company's unproved property costs are associated with properties acquired in the Kerr-McGee and Western acquisitions in 2006 and 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 are 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 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 determination of whether 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, which includes, for example, analyzing 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 or proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory drilling costs are expensed in that period. 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 a future period.

Proved Reserves

In December 2009, Anadarko adopted revised oil and gas reserve estimation and disclosure requirements that conform the definition of proved reserves to the SEC Modernization of Oil and Gas Reporting rules, which were issued by the SEC at the end of 2008. These rules require that the average, first-day-of-the-month price during the 12-month period preceding the end of the year, rather than the year-end price, be used when estimating reserve quantities and permit the use of reliable technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserve volumes. Prior-year data are presented in accordance with FASB oil and gas disclosure requirements effective during those periods; however, historical information has been reclassified to conform to the significant geographic areas required to be disclosed under the revised rules.

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., i.e., at prices as described above 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 upon 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 earlier. A material adverse change in the estimated volumes of proved reserves could have a negative impact on DD&A and could result in the recognition of an impairment.

Environmental Obligations and Other Contingencies

Management makes judgments and estimates in accordance with applicable accounting rules when it establishes reserves for environmental remediation, litigation and other contingent matters. Provisions for such matters are charged to expense when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. 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 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 these contingent liabilities and, in certain circumstances, third-party legal counsel or consultants are utilized.

Fair Value

The Company estimates fair value for derivatives, long-lived assets for impairment testing, reporting units for goodwill impairment testing, assets and liabilities exchanged in non-monetary transactions, guarantees, pension plan assets, initial measurements of AROs, assets and liabilities acquired in a business combination 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 a market-observable price for a similar asset or liability, the Company generally utilizes an income valuation approach. This approach is based upon management's best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk-adjusted discount rate. Such evaluations involve significant judgment and the results are based on expected future events or conditions, such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, economic and regulatory climates and other factors. The Company's estimates of future net cash flows are inherently imprecise because they reflect management's expectation of future conditions that 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.

Goodwill

At December 31, 2010, the Company had $5.3 billion of goodwill recorded related to past business combinations. The Company tests goodwill for impairment annually at October 1, or more often as facts and circumstances warrant. The first step in assessing whether an impairment of goodwill is necessary is to compare the fair value of the reporting unit to which goodwill has been assigned to the carrying amount of the associated net assets and goodwill. A reporting unit is an operating segment or a component that is one level below an operating segment. Anadarko has allocated goodwill to three reporting units: oil and gas exploration and production, gathering and processing, and transportation. At December 31, 2010, these reporting units have goodwill balances of $5.2 billion, $134 million and $5 million respectively.

During the second quarter of 2010, a decline in the fair value of Anadarko's oil and gas exploration and production reporting unit was indicated as a result of the Deepwater Horizon events and general uncertainty arising in connection with the Moratorium and uncertain regulatory impacts. See *Note 2—Deepwater Horizon Events* and *Note 15—Contingencies—Deepwater Drilling Moratorium and Other Related Matters* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. The Company completed an interim goodwill impairment test of the oil and gas exploration and production reporting unit at June 30, 2010, and the results of the test indicated no impairment. In addition, the Company completed its October 1, 2010, annual goodwill impairment tests with no goodwill impairment indicated. Although Anadarko cannot predict whether goodwill will be impaired in the future, and impairment charges may occur if the Company is unable to replace the value of its depleting asset base or if other adverse events (for example, lower sustained oil and gas prices) reduce the fair value of the associated reporting unit. Also, uncertainty related to the Deepwater Horizon events, difficulty or potential delays in obtaining drilling permits or other unanticipated events could trigger additional goodwill impairment tests in the near term, the results of which may have a material adverse impact on the Company's results of operations.

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. 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 observed 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 reporting unit, the Company assumes production profiles utilized 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 utilize based upon the risks inherent in Anadarko's operations.

For the Company's gathering and processing and transportation reporting units, the Company estimates fair value by applying an estimated multiple to projected 2011 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 goodwill impairments. 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. Based on the Company's most recent goodwill impairment tests, it was concluded that the fair value of each reporting unit substantially exceeded the carrying value of the reporting unit. Therefore, no goodwill impairment was indicated.

Impairment of 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 utilizes an income approach when market information for the same or similar assets does not exist. This fair-value approach requires use of management's best estimates, including asset production profiles and cost expectations, combined with inputs a market participant would use, e.g., prices and discount rates.

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. Unrealized gains or losses on derivatives are recorded to Anadarko's current earnings.

Benefit Plan Obligations

The Company has non-contributory U.S. defined-benefit pension plans, including both qualified and supplemental plans, and a foreign contributory defined-benefit pension plan. 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 and postretirement 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 rates of return on plan assets, the rate of future increases in compensation levels of participating employees and the future level of health care costs.

Discount rate

The discount-rate assumption used by the Company represents an estimate of the interest rate at which the pension and other postretirement obligations could effectively be settled on the measurement date. The Company currently uses a yield-curve analysis to support the discount-rate assumption for the plans. This analysis involves the creation of a hypothetical Aa spot yield curve represented by a series of high-quality, non-callable, marketable bonds, and discounting the estimated cash flows associated with benefits to be provided under each plan using interest rates on the curve that correspond to the expected timing of payment. The present value of future plan benefits determined in this manner is then used to estimate a single plan-specific discount rate that equates such present value with the corresponding future undiscounted cash flows. Application of this method resulted in a weighted-average discount-rate assumption (weighted by the plan-level benefit obligation) at December 31, 2010, of 4.75% for pension plans and 5.25% for other postretirement plans.

Expected long-term rate of return

The expected long-term rate of return on plan assets assumption was determined using the year-end 2010 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 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 experience significant volatility.

To measure the net periodic pension cost for its funded pension plans for the year ended December 31, 2010, Anadarko assumed an average long-term rate of return of 7.5%. A variation in this assumption of 25 basis points would have changed the measure of 2010 net periodic pension cost by $3 million, with higher investment return assumption resulting in lower recognized expense.

Rate of compensation increases

The Company's 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. The benefit obligations at December 31, 2010 and 2009 reflect the weighted-average assumed rate of increase in long-term compensation levels of 5.0% annually.

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. A 10% annual rate of increase in the per-capita cost of covered health care benefits was assumed for 2011, decreasing gradually to 5% in 2018 and beyond.

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.

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 payments and receipts denominated in foreign currencies. These risks can affect revenues and cash flow 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 derivative instruments utilized by the Company include futures, swaps, options and fixed-price physical-delivery contracts. The volume of commodity derivative instruments utilized 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 its counterparties in order to satisfy these margin requirements. For additional information about the Company's current derivative-related requirements see *Liquidity and Capital Resources—Effects of Credit Downgrade* under Item 7 of this Form 10-K.

For information regarding the Company's accounting policies and additional information related to the Company's derivative and financial instruments, see *Note 1—Summary of Significant Accounting Policies, Note 9—Derivative Instruments* and *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

ENERGY 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 flow significantly decline or rise. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if future oil and gas commodity prices experience a sustained, significant decline. Below is a sensitivity analysis of 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 equity production of 398 Bcf of natural gas and 47 MMBbls of crude oil at December 31, 2010. At December 31, 2010, the Company had a net derivative asset position of $293 million on these derivative instruments. Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $331 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $267 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instruments.

Derivative Instruments Held for Trading Purposes At December 31, 2010, the Company had a net derivative asset position of $19 million (gains of $34 million and losses of $15 million) on derivative instruments entered into for trading purposes. Utilizing the actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would not materially impact the Company's loss or gain 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 At December 31, 2010, $299 million of WES borrowings under its RCF and Term Loan, which are included in Anadarko's reported debt balance, were subject to variable interest rates. The remaining reported balance of Anadarko's long-term debt in the Company's Consolidated Balance Sheets was at fixed interest rates. The Company's $2.9 billion of LIBOR-based obligations, which are presented net of preferred investments in two non-controlled entities on the Company's Consolidated Balance Sheets, give rise to minimal net interest-rate risk exposure because coupons on the related preferred investments are also LIBOR based. See *Note 8—Investments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. A 10% increase in LIBOR would not materially impact the Company's interest cost.

Increases in market rates of interest will unfavorably impact the interest cost of future debt issuances. To mitigate this risk, in December 2008 and January 2009, Anadarko entered into interest-rate swap agreements with a combined notional principal amount of up to $3.0 billion, whereby the Company locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR. Since the swaps were initiated, the Company refinanced a portion of its 2011 and 2012 debt maturities. The Company has $512 million of remaining scheduled debt maturities for 2011 and 2012, which include payments on the Company's capital lease obligations and repayments of WES's RCF, or $1.2 billion including the Zero Coupons, which could be put to the Company in 2012. The Company may settle some or all of its interest-rate swap positions in connection with future debt issuances, if any, and will settle any remaining positions when the interest-rate swaps are scheduled to terminate in 2011 and 2012. At December 31, 2010, the Company had a net derivative liability position of $233 million related to interest-rate swaps, $181 million of which is associated with instruments settling in October 2011. A 10% increase or decrease in the three-month LIBOR interest-rate curve would increase or decrease, respectively, the aggregate fair value of outstanding interest-rate swaps agreements by approximately $42 million. For a summary of the Company's open interest-rate derivative positions, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

In June 2010, Moody's lowered the Company's senior unsecured credit rating from "Baa3" to "Ba1." For additional information concerning the effects on interest rates related to the downgrade, see *Liquidity and Capital Resources* under Item 7 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. At December 31, 2010, near-term foreign-currency-denominated expenditures are expected to be primarily in euros, Brazilian reais and British pounds sterling. Management mitigates a portion of its exposure to foreign-currency exchange-rate risk, as discussed below.

With respect to its international oil and gas development projects, Anadarko is a party to contracts containing commitments extending through January 2012 that are impacted by euro-to-U.S. dollar exchange rates. During the first quarter of 2010, the Company purchased approximately $210 million U.S. dollar equivalent of euros (€) in order to manage euro exchange-rate risk relative to the U.S. dollar for 2010 euro-denominated expenditures. At December 31, 2010, euro-denominated cash of approximately €130 million, or $174 million in U.S. dollar equivalent, is included in cash and cash equivalents. Additionally, Anadarko entered into euro-U.S. dollar collars, which are effective during 2011, for an aggregate notional principal amount of €113 million. The combination of euro purchases already executed and financial collars in effect during 2011 substantially mitigates Anadarko's exposure to fluctuations in the euro-to-U.S. dollar exchange rate inherent in its existing capital expenditure commitments.

The Company also has risk related to exchange-rate changes applicable to cash held in escrow pending final determination of the Company's Brazilian tax liability attributable to its 2008 divestiture of the Peregrino field offshore Brazil. 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

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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, 2010. This assessment was based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we believe that as of December 31, 2010, the Company's internal control over financial reporting is 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, 2010.

James T. Hackett
Chairman and Chief Executive Officer

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

February 23, 2011

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, 2010, based on criteria established in *Internal Control—Integrated Framework* 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, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of income, equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated February 23, 2011 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
February 23, 2011

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, 2010 and 2009, and the related consolidated statements of income, equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, 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, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 23, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Houston, Texas
February 23, 2011

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

millions except per-share amounts	Years Ended December 31, 2010	2009	2008
Revenues and Other			
Natural-gas sales	**$ 3,420**	$ 2,924	$ 5,770
Oil and condensate sales	**5,592**	4,022	6,425
Natural-gas liquids sales	**997**	536	802
Gathering, processing and marketing sales	**833**	728	1,082
Gains (losses) on divestitures and other, net	**142**	133	1,083
Reversal of accrual for DWRRA dispute (Note 15)	**—**	657	—
Total	**10,984**	9,000	15,162
Costs and Expenses			
Oil and gas operating	**830**	859	1,036
Oil and gas transportation and other	**816**	664	621
Exploration	**974**	1,107	1,369
Gathering, processing and marketing	**615**	617	800
General and administrative	**982**	983	866
Depreciation, depletion and amortization	**3,714**	3,532	3,194
Other taxes	**1,068**	746	1,452
Impairments	**216**	115	223
Total	**9,215**	8,623	9,561
Operating Income (Loss)	**1,769**	377	5,601
Other (Income) Expense			
Interest expense	**855**	702	732
(Gains) losses on commodity derivatives, net	**(893)**	408	(561)
(Gains) losses on other derivatives, net	**285**	(582)	7
Other (income) expense, net	**(119)**	(43)	55
Total	**128**	485	233
Income (Loss) from Continuing Operations Before Income Taxes	**1,641**	(108)	5,368
Income Tax Expense (Benefit)	**820**	(5)	2,148
Income (Loss) from Continuing Operations	**821**	(103)	3,220
Income from Discontinued Operations, net of taxes	**—**	—	63
Net Income (Loss)	**821**	(103)	3,283
Net Income Attributable to Noncontrolling Interests	**60**	32	23
Net Income (Loss) Attributable to Common Stockholders	**$ 761**	$ (135)	$ 3,260
Amounts Attributable to Common Stockholders			
Income (loss) from continuing operations attributable to common stockholders	**$ 761**	$ (135)	$ 3,197
Income (loss) from discontinued operations, net of taxes	**—**	—	63
Net income (loss) attributable to common stockholders	**$ 761**	$ (135)	$ 3,260
Per Common Share (amounts attributable to common stockholders):			
Income (loss) from continuing operations attributable to common stockholders—basic	**$ 1.53**	$ (0.28)	$ 6.79
Income (loss) from continuing operations attributable to common stockholders—diluted	**$ 1.52**	$ (0.28)	$ 6.78
Income (loss) from discontinued operations, net of taxes—basic	**$ —**	$ —	$ 0.13
Income (loss) from discontinued operations, net of taxes—diluted	**$ —**	$ —	$ 0.13
Net income (loss) attributable to common stockholders—basic	**$ 1.53**	$ (0.28)	$ 6.92
Net income (loss) attributable to common stockholders—diluted	**$ 1.52**	$ (0.28)	$ 6.91
Average Number of Common Shares Outstanding—Basic	**495**	480	465
Average Number of Common Shares Outstanding—Diluted	**497**	480	466
Dividends (per Common Share)	**$ 0.36**	$ 0.36	$ 0.36

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

millions	December 31, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 3,680**	$ 3,531
Accounts receivable, net of allowance:		
Customers	**1,032**	1,019
Others	**1,391**	1,033
Other current assets	**572**	500
Total	**6,675**	6,083
Properties and Equipment		
Cost	**54,815**	50,344
Less accumulated depreciation, depletion and amortization	**16,858**	13,140
Net properties and equipment	**37,957**	37,204
Other Assets	**1,616**	1,514
Goodwill and Other Intangible Assets	**5,311**	5,322
Total Assets	**$ 51,559**	$ 50,123
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	**$ 2,726**	$ 2,876
Accrued expenses	**1,097**	948
Current portion of long-term debt	**291**	—
Total	**4,114**	3,824
Long-term Debt	**12,722**	11,149
Midstream Subsidiary Note Payable to a Related Party	**—**	1,599
Other Long-term Liabilities		
Deferred income taxes	**9,861**	9,925
Other	**3,423**	3,211
Total	**13,284**	13,136
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 513.3 million and 509.0 million shares issued as of December 31, 2010 and 2009, respectively)	**51**	50
Paid-in capital	**7,496**	7,243
Retained earnings	**14,449**	13,868
Treasury stock (17.1 million and 16.4 million shares as of December 31, 2010 and 2009, respectively)	**(763)**	(721)
Accumulated other comprehensive income (loss)	**(549)**	(512)
Total Stockholders' Equity	**20,684**	19,928
Noncontrolling interests	**755**	487
Total Equity	**21,439**	20,415
Total Liabilities and Equity	**$ 51,559**	$ 50,123

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

millions	Preferred Stock	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
	Total Stockholders' Equity							
Balance at December 31, 2007	$ 45	$ 47	$ 5,511	$11,089	$ (55)	$ (273)	$ —	$ 16,364
Net income (loss)	—	—	—	3,260	—	—	23	3,283
Preferred stock repurchased and retired	(45)	—	—	—	—	—	—	(45)
Common stock issued	—	—	189	—	—	—	—	189
Dividends—common	—	—	—	(170)	—	—	—	(170)
Repurchase of common stock	—	—	—	—	(631)	—	—	(631)
Sale of subsidiary units	—	—	—	—	—	—	343	343
Contributions from and (distributions to) noncontrolling interest owners and other, net	—	—	(4)	—	—	—	(5)	(9)
Reclassification of previously deferred derivative losses to net income	—	—	—	—	—	14	—	14
Pension and other postretirement plans adjustments	—	—	—	—	—	(182)	—	(182)
Balance at December 31, 2008	—	47	5,696	14,179	(686)	(441)	361	19,156
Net income (loss)	—	—	—	(135)	—	—	32	(103)
Common stock issued	—	3	1,547	—	—	—	—	1,550
Dividends—common	—	—	—	(176)	—	—	—	(176)
Repurchase of common stock	—	—	—	—	(35)	—	—	(35)
Sale of subsidiary units	—	—	—	—	—	—	120	120
Contributions from and (distributions to) noncontrolling interest owners, net	—	—	—	—	—	—	(26)	(26)
Reclassification of previously deferred derivative losses to net income	—	—	—	—	—	22	—	22
Pension and other postretirement plans adjustments	—	—	—	—	—	(94)	—	(94)
Other	—	—	—	—	—	1	—	1
Balance at December 31, 2009	—	**50**	**7,243**	**13,868**	**(721)**	**(512)**	**487**	**20,415**
Net income (loss)	—	—	—	**761**	—	—	**60**	**821**
Common stock issued	—	**1**	**253**	—	—	—	—	**254**
Dividends—common	—	—	—	**(180)**	—	—	—	**(180)**
Repurchase of common stock	—	—	—	—	**(42)**	—	—	**(42)**
Sale of subsidiary units	—	—	—	—	—	—	**338**	**338**
Distributions to noncontrolling interest owners and other, net	—	—	—	—	—	—	**(130)**	**(130)**
Reclassification of previously deferred derivative losses to net income	—	—	—	—	—	**17**	—	**17**
Pension and other postretirement plans adjustments	—	—	—	—	—	**(54)**	—	**(54)**
Balance at December 31, 2010	**$ —**	**$ 51**	**$ 7,496**	**$14,449**	**$ (763)**	**$ (549)**	**$ 755**	**$ 21,439**

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

millions	Years Ended December 31, 2010	2009	2008
Net Income (Loss)	**$ 821**	$ (103)	$ 3,283
Other Comprehensive Income (Loss), net of taxes			
Reclassification of previously deferred derivative losses to net income [1]	**17**	22	14
Pension and other postretirement plans adjustments:			
Net gain (loss) incurred during period [2]	**(91)**	(131)	(187)
Prior service credit (cost) incurred during period [3]	**(4)**	—	(4)
Amortization of net actuarial loss and prior service cost to net periodic benefit cost [4]	**41**	37	9
Total pension and other postretirement plans adjustments	**(54)**	(94)	(182)
Other	**—**	1	1
Total	**(37)**	(71)	(167)
Comprehensive Income (Loss)	**784**	(174)	3,116
Comprehensive Income Attributable to Noncontrolling Interests	**60**	32	23
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ 724**	$ (206)	$ 3,093

(1) Net of income tax benefit (expense) of $(9) million, $(12) million, and $(8) million for the years ended December 31, 2010, 2009 and 2008, respectively.

(2) Net of income tax benefit (expense) of $52 million, $74 million, and $107 million for the years ended December 31, 2010, 2009 and 2008, respectively.

(3) Net of income tax benefit (expense) of $2 million, zero, and $2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

(4) Net of income tax benefit (expense) of $(23) million, $(21) million, and $(5) million for the years ended December 31, 2010, 2009 and 2008, respectively.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

millions	Years Ended December 31, 2010	2009	2008
Cash Flows from Operating Activities			
Net income (loss)	**$ 821**	$ (103)	$ 3,283
Less income from discontinued operations, net of taxes	**—**	—	63
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**3,714**	3,532	3,194
Deferred income taxes	**(123)**	(165)	(22)
Dry hole expense and impairments of unproved properties	**682**	780	1,005
Impairments	**216**	115	223
(Gains) losses on divestitures, net	**(29)**	(44)	(993)
Unrealized (gains) losses on derivatives, net	**(114)**	717	(922)
Reversal of accrual for DWRRA dispute (Note 15)	**—**	(657)	—
Other	**213**	183	125
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	**(172)**	(290)	803
Increase (decrease) in accounts payable and accrued expenses	**(157)**	269	158
Other items—net	**196**	(411)	(344)
Cash provided by (used in) operating activities—continuing operations	**5,247**	3,926	6,447
Cash provided by (used in) operating activities—discontinued operations	**—**	—	(5)
Net cash provided by (used in) operating activities	**5,247**	3,926	6,442
Cash Flows from Investing Activities			
Additions to properties and equipment and dry hole costs	**(5,008)**	(4,352)	(4,801)
Divestitures of properties and equipment and other assets	**70**	176	2,455
Other—net	**(26)**	(60)	(182)
Net cash provided by (used in) investing activities	**(4,964)**	(4,236)	(2,528)
Cash Flows from Financing Activities			
Borrowings, net of issuance costs	**3,198**	1,975	—
Repayments of debt	**(1,879)**	(1,470)	(1,960)
Repayment of midstream subsidiary note payable to a related party	**(1,599)**	(140)	(461)
Increase (decrease) in accounts payable, banks	**7**	(139)	89
Dividends paid	**(180)**	(176)	(170)
Repurchase of common stock	**(42)**	(35)	(631)
Repurchase and retirement of preferred stock	**—**	—	(45)
Issuance of common stock, including tax benefit on stock option exercises	**107**	1,372	25
Sale of subsidiary units	**338**	120	343
Distributions to noncontrolling interest owners	**(48)**	(29)	(16)
Other financing activities	**(24)**	3	4
Net cash provided by (used in) financing activities	**(122)**	1,481	(2,822)
Effect of Exchange Rate Changes on Cash	**(12)**	—	—
Net Increase (Decrease) in Cash and Cash Equivalents	**149**	1,171	1,092
Cash and Cash Equivalents at Beginning of Period	**3,531**	2,360	1,268
Cash and Cash Equivalents at End of Period	**$ 3,680**	$ 3,531	$ 2,360

See accompanying Notes to Consolidated Financial Statements.

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 and natural gas liquids (NGLs). The Company also engages in the gathering, processing, and treating of natural gas, and transporting natural gas, crude oil and NGLs. The Company also participates in the hard minerals business through its ownership of non-operated joint ventures and royalty arrangements. 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 and losses and distributions. Other investments are carried at original cost. Investments accounted for using the equity- 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 In preparing financial statements in accordance with accounting principles generally accepted in the United States, management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Management evaluates its estimates and related assumptions regularly, including those related to the value of properties and equipment, proved reserves, goodwill, intangible assets, asset retirement obligations, litigation reserves, environmental liabilities, pension assets and 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).

1. Summary of Significant Accounting Policies (Continued)

In determining fair value, the Company utilizes 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.

In arriving at fair-value estimates, the Company utilizes 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 rate of interest at each balance sheet date. Debt fair values, as disclosed in Note 11, 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 and goodwill, asset retirement obligations and 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. Crude oil and condensate are sold primarily to marketers, gatherers and refiners. NGLs are sold primarily to direct end-users, refiners and marketers. The majority of the Company's receivables are paid within two months following the month of purchase. In 2010, 2009 and 2008, there were no sales to individual customers that exceeded 10% of the Company's total sales revenues.

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 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 estimated remaining recoverable reserves of the well, a liability is recognized. No receivables are recorded for those wells on which the Company has taken less than its proportionate share of production.

The Company enters into buy/sell arrangements for a portion of its crude-oil production. Under these arrangements, barrels are sold at prevailing market prices at a location, and in an additional transaction entered into in contemplation of the sale transaction with the same third party, barrels are re-purchased at a different location at the market prices prevailing at that location. The barrels are then sold at prevailing market prices at the re-purchase location. These arrangements are often required by private transporters. In these transactions, the re-purchase price is more than the original sales price with the difference representing a transportation fee. Other buy/sell arrangements are entered in order to shift the ultimate sales point of the Company's production to a more liquid location, thereby avoiding potential marketing fees and other market-price reductions. In these transactions, the sales price in the field and the re-purchase price are each at prevailing market prices at the respective locations. Anadarko uses these buy/sell arrangements in its marketing and trading activities and, as such, reports these transactions in the Consolidated Statements of Income on a net basis.

Anadarko provides gathering, processing, treating and transportation 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.

1. Summary of Significant Accounting Policies (Continued)

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, as well as realized and unrealized gains and losses on such marketing activities, are included in gathering, processing and marketing sales.

Cash Equivalents The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

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. At December 31, 2010 and 2009, accounts receivable are shown net of allowance for uncollectible accounts of $9 million and $11 million, respectively.

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. Acquisition costs and costs of drilling exploratory wells are capitalized pending determination of whether proved reserves can be attributed to the area as a result of drilling the well. If management determines that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells are charged to exploration expense. Acquisition costs of unproved properties are assessed for impairment during the holding period and 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 terms of the leases, 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.

Capitalized Interest Interest is capitalized as part of the historical cost of developing and constructing assets for significant projects. Significant oil and gas investments in unproved properties, significant exploration and development projects for which DD&A is not currently recognized, and exploration or development activities that are in progress 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, along with other capitalized costs related to that asset.

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.

Impairments Properties and equipment, net of salvage value, are reviewed for impairment at the lowest level for which identifiable cash flows are independent of cash flows from other assets, and when facts and circumstances indicate that net book values may not be recoverable. In performing this review, an undiscounted cash flow test is performed on the impairment unit. If the sum of the undiscounted estimated 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.

Depreciation, Depletion and Amortization Costs of drilling and equipping successful wells, costs to construct or acquire facilities other than offshore platforms and associated asset retirement costs 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 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 The Company tests goodwill for impairment annually, or more often as facts and circumstances warrant. During 2009, the Company changed its annual goodwill impairment testing date from January 1 to October 1, to ensure the completion of the annual goodwill impairment test prior to the end of the annual reporting period, and to align impairment testing procedures with year-end financial reporting. Changes in goodwill may result from, among other things, impairments, future acquisitions or future divestitures. See Note 6.

Other intangible assets represent contractual rights obtained in connection with a business combination that had favorable contractual terms relative to market at the acquisition date. Other intangible assets are amortized over their estimated useful lives and are reviewed for impairment whenever impairment indicators are present. See Note 6.

Derivative Instruments Anadarko uses derivative instruments to manage its exposure to cash-flow variability resulting from commodity price and interest-rate risk. All derivatives that do not satisfy the normal purchases and sales exception criteria 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. Where the Company has the contractual right and intends to net settle, derivative assets and liabilities are reported on a net basis.

1. Summary of Significant Accounting Policies (Continued)

Realized and unrealized gains and losses on derivative instruments are recognized on a current basis. Net derivative 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 9.

Accounts Payable Included in accounts payable at December 31, 2010 and 2009, are liabilities of $259 million and $252 million, respectively, representing the amount by which checks issued, but not presented to the Company's banks for collection, exceed balances in applicable bank accounts, and 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 its business. Except for legal contingencies acquired in a business combination, which are recorded at fair value, the Company accrues losses associated with legal claims when such losses are probable and reasonably estimable. 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 2 and Note 15.

Environmental Contingencies Except for environmental contingencies acquired in a business combination, which are recorded at fair value, the Company accrues losses associated with environmental obligations when such losses are probable and can be reasonably estimated. 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 as 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 2 and Note 15.

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 rate of return on plan assets (for funded pension plans), the rate of future compensation increases and the health care cost trend rate. Other assumptions involve demographic factors such as retirement, mortality and turnover. The Company evaluates and updates its actuarial assumptions at least annually. See Note 20.

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 7.

Income Taxes The Company files various United States 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 bases. 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. See Note 17.

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 also grants 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).

1. Summary of Significant Accounting Policies (Continued)

The fair value of stock option awards is determined on the date of grant using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of Anadarko common stock on the grant date. For equity- and liability-classified performance units, fair value is determined using a Monte Carlo simulation.

The Company records compensation cost, net of estimated forfeitures, for share-based compensation awards over the requisite service period. As each award of stock options or non-vested equity shares vests, an adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the vested awards. For share-based awards that contain service conditions, compensation cost is recorded using the straight-line method. If the requisite service period is satisfied, compensation cost is not adjusted. For liability-classified performance units, expense is recognized only for those awards that ultimately vest using the market price of Anadarko common stock on the date the awards are earned. See Note 13.

Discontinued Operations In November 2006, Anadarko sold its wholly owned subsidiary, Anadarko Canada Corporation. The results of the Company's Canadian operations have been classified as discontinued operations in the Consolidated Statements of Income and Consolidated Statements of Cash Flows for 2008 and primarily relate to adjustments to an indemnity obligation provided by the Company to the purchaser, as well as expenses associated with finalizing exit activities. Unless otherwise indicated, information presented in the Notes to Consolidated Financial Statements relates only to Anadarko's continuing operations. See Note 15.

Earnings Per Share The Company's basic earnings per share (EPS) amounts have been computed based on the average number of shares of common stock outstanding for the period and include 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 12.

Changes in Accounting Principles The Company adopted a new fair-value measurement standard on January 1, 2008. The standard defines fair value, establishes a framework for measuring fair value under existing accounting pronouncements that require fair-value measurements and expands fair-value measurement disclosures. The Company elected to implement the standard with the one-year deferral permitted for non-financial assets and non-financial liabilities, except those non-financial items recognized or disclosed at fair value on a recurring basis (at least annually). The deferral period ended on January 1, 2009, and the Company began applying the fair-value framework to non-financial assets and non-financial liabilities initially measured at fair value, such as assets and liabilities acquired in a business combination, impaired long-lived assets (asset groups), intangible assets and goodwill, asset retirement obligations and exit or disposal costs, and certain capital lease assets.

Effective January 1, 2010, the Company adopted revised oil and gas reserve estimation standards. This standard allows the use of reliable technology in determining estimates of proved reserve quantities and requires the use of a 12-month first-day-of-the-month average price to estimate proved reserves. Adoption of this standard did not have a material impact on depreciation, depletion and amortization expense.

2. Deepwater Horizon Events

Background In April 2010, the Macondo well in the Gulf of Mexico, in which Anadarko holds a 25% non-operating leasehold interest, discovered hydrocarbon accumulations. During suspension operations, the well blew out, an explosion occurred on the *Deepwater Horizon* drilling rig, and the drilling rig sank, resulting in the release of hydrocarbons into the Gulf of Mexico. Eleven people lost their lives in the explosion and subsequent fire, and others sustained personal injuries. Response and cleanup efforts are being conducted by BP Exploration & Production Inc. (BP), the operator and 65% owner of the Macondo lease, and by other parties, all under the direction of the Unified Command of the United States Coast Guard (USCG).

On July 15, 2010, after several attempts to contain the oil spill, BP successfully installed a capping stack that shut in the well and prevented the further release of hydrocarbons. Installation of the capping stack was a temporary solution that was followed by a successful "static kill" cementing operation completed on August 5, 2010. The Macondo well was permanently plugged on September 19, 2010, when BP completed a "bottom kill" cementing operation in connection with the successful interception of the well by a relief well. Investigations by the federal government and other parties into the cause of the well blowout, explosion, and resulting oil spill, as well as other matters arising from or relating to these events, are ongoing.

Based on information provided by BP to the Company, BP has incurred costs of approximately \$16.5 billion (including costs associated with USCG invoices totaling \$606 million) through December 31, 2010, related to spill response and containment, relief-well drilling, grants to certain Gulf Coast states for cleanup costs, local tourism promotion, monetary damage claims and federal costs. In addition, BP has incurred more than \$1.4 billion of costs since December 31, 2010.

BP has sought reimbursement from Anadarko for amounts BP has paid or committed to pay for spill-response efforts, grants, damage claims and costs incurred by the federal government through provisions of the operating agreement (OA), which is the contract governing the relationship between BP and the non-operating OA parties to the Mississippi Canyon Block 252 lease in which the Macondo well is located (Lease). BP has invoiced the Company an aggregate \$4.0 billion for what BP considers to be Anadarko's 25% proportionate share of actual costs through December 31, 2010. In addition, BP has invoiced Anadarko for anticipated near-term future costs related to the Deepwater Horizon events. Anadarko has withheld reimbursement to BP for Deepwater Horizon event-related invoices pending the completion of various ongoing investigations into the cause of the well blowout, explosion, and subsequent release of hydrocarbons. Final determination of the root causes of the Deepwater Horizon events could materially impact the Company's potential obligations under the OA.

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 USCG referencing their identification as a "responsible party or guarantor" (RP) under the Oil Pollution Act of 1990 (OPA), and the United States Department of Justice (DOJ) has also filed a civil lawsuit against such parties seeking to, among other things, confirm each party's identified RP status. Under OPA, RPs may be held 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 directly related to the spill and spill cleanup. The USCG has directly invoiced the identified RPs for reimbursement of spill-related response costs incurred by the USCG and other federal and state agencies. The identified RPs each received identical invoices for total costs, without specification or stipulation of any allocation of costs between or among the identified RPs. To date, as operator, BP has paid all USCG invoices, thereby satisfying the joint and several obligation of the identified RPs to the USCG for these costs. BP has also made repeated public statements regarding its intention to continue to pay 100% of costs associated with cleanup efforts, claims and reimbursements related to the Deepwater Horizon events.

The following analysis applies relevant accounting guidance to the Deepwater Horizon events to determine the Company's liability accrual as of December 31, 2010. The process for quantifying the Company's Deepwater Horizon event-related liability accrual involves the identification of all potential costs and the grouping of these costs in a manner that enables the Company to apply relevant accounting guidance to each cost based upon the qualitative characteristics of such costs. This is appropriate because satisfaction of liability-recognition criteria may vary depending upon the type of costs being analyzed. For example and as discussed more fully below, contingent contractual liabilities (such as those arising under the OA) and contingent environmental liabilities (such as those arising under OPA) are subject to substantially similar liability-recognition criteria; however, circumstances under which such criteria are considered satisfied are different.

2. Deepwater Horizon Events (Continued)

As discussed and analyzed below, after applying the relevant accounting guidance to the Company's Deepwater Horizon event-related contingent liabilities, the Company's aggregate liability accrual for these amounts is zero as of December 31, 2010. The zero liability accrual is not intended to represent an opinion of the Company that it will not incur any future liability related to the Deepwater Horizon events. Rather, the zero liability accrual is based on currently available facts and the application of accounting rules to this set of facts where the relevant accounting rules do not allow for loss recognition where a potential loss is not considered "probable" or cannot be reasonably estimated.

In quantifying its potential Deepwater Horizon event-related liabilities, the Company has made certain assumptions regarding facts that are the subject of continuing investigations, the duration and extent of ongoing cleanup activities, and current and potential future damage claims. Thus, the Company's zero liability accrual for the Deepwater Horizon events is subject to change in the future, perhaps materially. 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, (ii) OPA-related environmental costs, and (iii) other contingent liabilities.

OA Contingent Liabilities OA contingent liabilities relate to Anadarko's potential responsibility for a 25% share of costs incurred by BP through December 31, 2010, for which BP has sought reimbursement from Anadarko under the OA. Accounting standards require the Company to accrue contingent liabilities arising under the terms of the OA if it is both "probable" that a liability has been incurred and the amount of the liability can be reasonably estimated.

With respect to the operator's duties and liabilities, the OA provides the following:

- BP, as operator, owes duties to the non-operating parties (including Anadarko) to perform the drilling of the well in a good and workmanlike manner and to comply with all applicable laws and regulations;
- BP, as operator, is not liable to non-operating parties for losses sustained or liabilities incurred, except for losses resulting from the operator's gross negligence or willful misconduct; and
- liability for losses, damages, costs, expenses, or claims involving activities or operations shall be borne by each party in proportion to its participating interest, except that when liability results from the gross negligence or willful misconduct of a party, that party shall be solely responsible for liability resulting from its gross negligence or willful misconduct.

The Company believes publicly available evidence indicates that the blowout of the well, the explosion on the *Deepwater Horizon* drilling rig, and the subsequent release of hydrocarbons were preventable and the direct result of BP's decisions, omissions and actions, and likely constitute gross negligence or willful misconduct by BP. BP has issued public statements indicating that it disagrees with this assessment. Under the OA, liabilities arising as a result of gross negligence or willful misconduct by BP are the sole responsibility of BP and are not chargeable to other OA parties, including Anadarko. In light of the foregoing, Anadarko does not consider OA contingent liabilities for Deepwater Horizon event-related costs invoiced by BP to the Company to satisfy the standard of "probable" required for loss recognition. Accordingly, as of December 31, 2010, pursuant to applicable accounting guidance, the Company has not recognized a liability in its Consolidated Balance Sheets for Deepwater Horizon event-related costs that have been invoiced by BP to Anadarko under the OA.

In the future, the Company may recognize a liability for Deepwater Horizon event-related costs invoiced by BP under the OA if new information arising from the legal discovery or adjudication process, hearings, other investigations, expert analysis, or testing alters the Company's current assessment as to the likelihood of the Company incurring a liability for its existing OA contingent obligations. In addition, BP, as the operator, may have enforceable indemnity obligations to certain of its contractors, for which BP may be able to obtain reimbursement from the Company under the OA for the Company's share of any such costs incurred by BP, notwithstanding BP's own gross negligence. The Company currently is not positioned to assess the validity of BP's ostensible indemnity obligations to its contractors, nor is the Company knowledgeable as to whether BP has incurred actual costs as a result of these indemnity provisions. As a result, the Company currently does not consider any losses attributable to potential indemnity obligations to be "probable," and is furthermore unable to reasonably estimate the amount of any such potential loss.

2. Deepwater Horizon Events (Continued)

OPA-Related Environmental Costs Under OPA, Anadarko may be held jointly and severally liable with all RPs for OPA-related environmental costs associated with the Deepwater Horizon events. Anadarko's treatment by the USCG as an identified RP arises as a result of Anadarko's status as a co-lessee in the Lease.

Applicable accounting guidance requires the Company to accrue an environmental liability if it is both "probable" that a liability has been incurred and the amount of the liability can be reasonably estimated. 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 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." Given that such liabilities are probable, applicable accounting guidance requires the Company to (i) estimate, on a gross basis, a range of total potential OPA-related environmental costs for the Deepwater Horizon events, and (ii) separately assess and estimate the Company's allocable share of the gross estimated costs.

OPA-related environmental costs that have been paid by BP and subsequently invoiced to Anadarko under the OA are accounted for as OA contingent liabilities (discussed above) rather than OPA-related environmental costs (discussed herein). Payment of OPA-related environmental costs by BP satisfies these liabilities for all identified RPs, including Anadarko, and has resulted in BP seeking reimbursement from Anadarko for these costs through the OA, thereby creating an OA contingent liability. The Company assumes that all OPA-related environmental costs incurred by BP and reported to the Company have been paid by BP, thereby satisfying those joint and several OPA-related environmental costs for all identified RPs.

Gross OPA-Related Environmental Cost Estimate The Company estimates the range of gross OPA-related environmental costs for all identified RPs to be $4.0 billion to $5.0 billion, excluding (i) $16.5 billion of costs incurred by BP as of December 31, 2010, which are considered and analyzed as OA contingent liabilities, and (ii) amounts the Company currently cannot reasonably estimate, which include OPA damage claims that may be filed subsequent to the first quarter of 2011, potential costs associated with penalties and fines, the costs associated with natural resource damage (NRD) assessments and NRD claims, and civil litigation damages. The costs that the Company currently cannot reasonably estimate may be significant.

Anadarko's gross OPA-related environmental cost estimate is comprised of spill-response costs and OPA damage claims. This cost estimate is based on cost information received from BP, certain assumptions discussed below, and publicly available information from the Gulf Coast Claims Facility (GCCF). The GCCF is an independent claims facility that was established in June 2010, as part of an agreement between the federal government and BP, to assist claimants in the submission and resolution of claims for costs and damages incurred as a result of the Deepwater Horizon events. As a non-operator, the Company is limited to formulating its estimates of spill-response costs and OPA damages based upon information provided by BP, publicly available information, and management's assumptions regarding a number of variables associated with the Deepwater Horizon events that remain uncertain or unknown. Although the Macondo well has been permanently plugged, the scope and extent of damages and cleanup activities continue to evolve, resulting in significant uncertainty as to the spill's ultimate impacts and associated costs. Accordingly, the Company believes that actual gross OPA-related environmental costs may vary, perhaps materially, from the Company's estimate.

2. Deepwater Horizon Events (Continued)

Spill-Response Costs and Assumptions Estimated spill-response costs are based on cost information received from BP, which was used to estimate activity-based cost run-rates for spill-response activities, which, in turn, were projected forward according to the Company's estimates of the potential duration and extent of the spill response and cleanup.

The Company's current cost estimate is based on the following assumptions:

- costs to operate, demobilize and decontaminate offshore well-site equipment and resources will continue through the first quarter of 2011; and
- at a minimum, costs will continue through the end of the first quarter of 2011, and end prior to the beginning of the third quarter of 2011, for the following activities:
  - shallow-water marine cleanup;
  - demobilization and decontamination of vessels deployed in open-water cleanup;
  - shoreline cleanup; and
  - federal, state and local spill mitigation and coordination.

The above costs may continue for periods longer than those assumed by the Company for purposes of formulating its cost estimate. However, the scope and extent of the above costs continue to evolve over time, which adversely impacts the Company's ability to reasonably estimate certain costs that may continue beyond the above-stated periods. The Company will continue to monitor and estimate costs as the scope and extent of required activities becomes more certain.

OPA Damage Claims OPA damages (other than NRD, discussed below) include costs associated with increased public-service expenses, damages to real or personal property, damages to subsistence users of natural resources, lost revenues, and lost profits and earning capacity. These damages are assessed pursuant to OPA and are limited, in general, to $75 million. However, the $75 million limit has not been applied for purposes of formulating the Company's cost-range estimate and may not be applicable where there is a finding of gross negligence, willful misconduct, or a violation of an applicable federal safety, construction, or operating regulation by an RP, an agent or employee of an RP, or a person acting pursuant to a contractual relationship with an RP.

The Company's cost estimate includes potential OPA damage claims and costs to administer those claims based on data received from BP and publicly available information from the GCCF. This claims information has been used to formulate estimates of the number of claims to be paid, the average expected per-claim payout, and costs to administer claims and operate claims offices projected for claims filed through the end of the first quarter of 2011.

The Company believes that new claims will continue to be filed beyond the end of the first quarter of 2011; however, the Company is currently unable to reasonably estimate the number, magnitude and administrative cost of claims that will be filed subsequent to the first quarter of 2011. The Company lacks visibility into, among other things, the processes associated with OPA damage claim approvals and claims administration, which significantly hinders the Company's ability to formulate a long-term estimate of potential OPA damage claims. Accordingly, the Company's cost estimate does not include amounts attributable to OPA damage claims that could be made subsequent to the end of the first quarter of 2011.

2. Deepwater Horizon Events (Continued)

Allocable Share of Gross OPA-Related Environmental Costs As discussed above, under applicable accounting guidance, the Company is required to estimate its allocable share of gross OPA-related environmental costs based on the Company's estimate of the allocation method and percentage that may ultimately apply. No agreed-upon or stipulated allocation of gross OPA-related environmental costs currently exists. As a result, the Company considered the following factors for purposes of estimating a range of its allocable share of these costs:

- *BP's payment to date of Deepwater Horizon event-related costs*—To date, BP has paid all Deepwater Horizon event-related costs and has repeatedly stated publicly and in congressional testimony that it will continue to pay all of these costs. The liability of all RPs for amounts payable under OPA is satisfied as BP funds these amounts. Accordingly, Anadarko's minimum allocable share of gross OPA-related environmental costs is zero where BP continues to fund 100% of OPA-related environmental costs. Furthermore, the Company believes that in order for BP to obtain reimbursement from Anadarko under the OA for OPA-related environmental costs paid by BP, BP must establish that it is entitled to reimbursement under the terms of the OA. As discussed above, the Company does not consider BP to be entitled to cost reimbursement under the OA.

- *Anadarko's OA sharing percentage*—If BP ceases paying any portion of the Deepwater Horizon event-related costs, the federal government could seek payment from all potential RPs under the joint and several liability provisions of OPA. Under this scenario, the Company estimates its maximum allocation of gross OPA-related environmental costs could be 25%, which is equivalent to Anadarko's OA sharing percentage. The Company does not consider an allocable percentage in excess of 25% to be reasonable based on BP's public statements that it intends to continue to honor its commitments in the Gulf of Mexico, the Company's assessment of BP's ability to continue funding all OPA-related environmental costs and the Company's assessment of the other OA party's ability to fund its share of potential costs. This estimate of a maximum allocation percentage assumes no allocation of gross OPA-related environmental costs to RPs that are not a party to the OA (non-OA RPs).

- *Allocation to non-OA RPs*—In addition to the parties to the OA, identified as RPs (including the Company), two non-OA RPs have been identified by the federal government. The allocation of costs to all potential RPs, including non-OA RPs, would likely reduce Anadarko's potential allocable share of gross OPA-related environmental costs to an amount less than Anadarko's 25% OA sharing percentage.

Based on the above, the Company has concluded that a range of 0-25% is appropriate as an estimate of its potential allocable share of gross OPA-related environmental costs. In prior periods, the Company concluded that no single allocation percentage within the 0-25% range was more likely than another, resulting in the Company accruing a liability of zero for its potential share of gross OPA-related environmental costs as required by applicable accounting guidance. At December 31, 2010, the Company considers zero to be the most likely allocable percentage within the original 0-25% range for allocation of gross OPA-related environmental costs and, under the applicable accounting guidance, continues to have a liability accrual of zero. The Company's assessment as to the most likely allocation percentage changed as a result of BP's continued funding of 100% of OPA-related environmental costs and BP's repeated public commentary regarding its ability and intent to continue to honor its Deepwater Horizon-related commitments. BP's funding and public commentary has continued subsequent to the release of BP's own investigation report as well as the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling's final report, which the Company considers significant in concluding that zero is the most likely allocation percentage within the 0-25% range.

2. Deepwater Horizon Events (Continued)

Other Contingencies

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 Clean Water Act (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 BP or the Company. Currently, the Company cannot reasonably estimate the amount of any federal, state or local penalties or fines that could be assessed or the extent to which such penalties or fines could be material to the Company's financial statements.

To date, no penalties or fines have been assessed against the Company or, to the Company's knowledge, any other party. However, on December 15, 2010, the DOJ, on behalf of the federal agencies involved in the spill response, filed a civil lawsuit in the United States District Court for the Eastern District of 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 the lawsuit, the DOJ states that civil penalties under the CWA may be assessed in an amount up to $1,100 per barrel of oil discharged or in cases involving gross negligence or willful misconduct in an amount up to $4,300 per barrel of oil discharged.

While Anadarko was named in the DOJ civil lawsuit, its status as a defendant does not mean that Anadarko will be assessed a penalty in that action. CWA penalties, in practice, are generally assessed on a party-specific basis and take into account several factors such as the party's degree of fault. The Company considers BP's actions, as well as the Company's lack of direct involvement in the spill significant for purposes of concluding that potential losses from CWA penalty assessments are not "probable." Neither the filing of the DOJ civil lawsuit nor the potential for BP to be found grossly negligent alters the Company's assessment of potential penalties under the CWA. Accordingly, the Company has not recorded a liability for potential CWA penalties at December 31, 2010.

In addition to determining that any potential liability for CWA penalties is not "probable," the Company currently cannot estimate the amount of any such penalty. Over the course of the spill, there have been several widely varying estimates of the ultimate spill volume by various groups. On August 2, 2010, the federal government published its spill-volume estimate of 4.9 million barrels, which was based on several assumptions and acknowledges variability of the flow rate over time, inherent imprecision in the federal government's ability to accurately estimate the flow rate, and uncertainty in evaporation and dispersion rates. In December 2010, BP stated publicly its intent to challenge the federal government's spill-volume estimate. The DOJ complaint does not reference or estimate a spill volume.

2. Deepwater Horizon Events (Continued)

In addition to spill-volume variability, there is significant uncertainty as to the Company's ultimate liability for potential CWA penalties, if any, as previous CWA penalty settlements vary greatly, have not been based solely on a simple per-barrel penalty assessment and have often been influenced by some or all of the following subjective factors included in the CWA:

- the degree of culpability involved;
- the seriousness of the violation;
- the economic benefit to the violator;
- any other penalties assessed for the same incident;
- the history of prior violations; and
- any mitigation efforts undertaken and the success of those efforts.

Based on the above factors, the significant uncertainty regarding the actual spill volume, and historic resolution through settlement, the Company currently is unable to reasonably estimate any potential CWA penalties.

Natural Resource Damages (NRD) This category includes costs to assess damages to natural resources resulting from the spill and/or spill-cleanup activities as well as 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, or 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 and the Department of Defense. These governmental departments, along with the five affected states, Alabama, Louisiana, Florida, Mississippi and Texas, are referred to as the "Co-Trustees." The Co-Trustees continue to conduct injury assessment and restoration planning. The assessment phase will continue as long as spill-cleanup activities are ongoing, and may extend for an unknown period of time subsequent to the completion date of spill-cleanup activities. Restoration planning is ongoing and will be completed subsequent to the completion of the injury assessment.

In October 2010, the Co-Trustees notified the identified RPs that certain "emergency restoration actions" were to commence. BP is working cooperatively with the Co-Trustees and has provided the Company with documentation of expenses associated with pre-funding the Co-Trustees' NRD assessment activities. NRD assessment costs, such as these, may change significantly as injury assessment and restoration planning continues. Thus, the Company is unable to project total NRD assessment costs at this time.

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, the state of Alabama has individually filed an NRD-related claim and the State of Louisiana is considering filing and has requested permission from the court to conduct discovery regarding the issue. At this time, the Company is unable to reasonably estimate the magnitude of any NRD claim until assessment and restoration planning is complete, which may take several years, or additional facts or information are revealed during legal discovery.

2. Deepwater Horizon Events (Continued)

Civil Litigation Damage Claims Numerous civil lawsuits have been filed against BP and other parties, including the Company, by fishing, boating and shrimping industry groups; restaurants; commercial and residential property owners; certain rig workers or their families; the State of Alabama and several of its political subdivisions; the DOJ; environmental non-governmental organizations; the Plaquemines Parish School Board, a political subdivision of the State of Louisiana; 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.

In August 2010, the United States Judicial Panel on Multidistrict Litigation created Multidistrict Litigation No. 2179 (MDL) to administer essentially all litigation filed in federal court involving Deepwater Horizon event-related claims. Federal Judge Carl Barbier presides over this MDL in the United States District Court for the Eastern District of Louisiana in New Orleans, Louisiana. The court issued a number of case management orders that establish a schedule for procedural matters, discovery and trial of the MDL cases. The court set for trial beginning in June 2011, one or more cases brought against BP as an RP under OPA, to serve as test cases for causation and damage issues. The court has not yet selected the specific OPA test cases to be tried. Also, the court scheduled a February 2012 trial to determine the liability issues and allocate liability among the parties involved in the Deepwater Horizon events. The parties to the MDL are actively engaged in discovery.

Lawsuits seeking to place limitations on the oil and gas industry's operations in the Gulf of Mexico, including those of the Company, have also been filed outside of the MDL by non-governmental organizations against various governmental agencies. These cases are filed in the United States District Court for the Southern District of Alabama, the Eastern District of Louisiana, and the District of Columbia and in the United States Court of Appeals for the Fifth Circuit.

Two separate class action complaints were filed in June and August 2010 in the United States District Court for the Southern District of New York on behalf of purported purchasers of the Company's stock between June 12, 2009, and June 9, 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 District Court for the Southern District of New York consolidated the two cases, and appointed The Pension Trust Fund for Operating Engineers and Employees' Retirement System of the Government of the Virgin Islands (Virgin Islands Group) to act as Lead Plaintiff. In January 2011, the Lead Plaintiff filed its Consolidated Amended Complaint. Prior to filing its Consolidated Amended Complaint, the Lead Plaintiff requested leave from the court to transfer this lawsuit to the United States District Court for the Southern District of Texas. The Company opposes the Lead Plaintiff's request to transfer the case to the District Court for the Southern District of Texas. The court has ordered the parties to brief the transfer of venue issue.

Also in June 2010, a shareholder derivative petition was filed in the 157th District Court of Harris County, Texas, by a shareholder of the Company against Anadarko (as a nominal defendant) and certain of its officers and current and certain former directors. The petition alleges breaches of fiduciary duties, unjust enrichment, and waste of corporate assets in connection with the Deepwater Horizon events. The plaintiffs seek certain changes to the Company's governance and internal procedures, disgorgement of profits, and reimbursement of litigation fees and costs. In November 2010, the court granted Anadarko's Motion to Dismiss for Lack of Jurisdiction and Special Exceptions and granted the plaintiffs 120 days to file an Amended Petition. 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. The Board duly considered the demand and in January 2011 determined that it would not be in the best interests of the Company to pursue the issues in the demand letter.

These proceedings are at a very early stage; accordingly, the Company currently cannot assess the probability of losses, or reasonably estimate a range of any potential losses related to the proceedings described above. The Company intends to vigorously defend itself, its officers and its directors in these proceedings.

2. Deepwater Horizon Events (Continued)

Liability Outlook As discussed above, the Company's aggregate Deepwater Horizon event-related liability accrual of zero as of December 31, 2010, is not intended to represent an opinion of the Company that it will not incur any future liability related to the Deepwater Horizon events. The Company's liability assessment is based on the application of relevant accounting guidance to the Company's understanding of currently available facts surrounding the Deepwater Horizon events. As more facts become known, it is reasonably possible that the Company may be required to recognize a liability related to the Deepwater Horizon events, and that the liability could be material to the Company's consolidated financial position, results of operations or cash flows.

The Company will continue to monitor the MDL and other legal proceedings discussed above as well as active federal investigations related to the Deepwater Horizon events, including investigations by The Deepwater Horizon Joint Investigation Team, the U.S. Chemical Safety Board, and the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. The Company cannot predict the nature of evidence that may be discovered during the course of legal proceedings and investigations, the timing of discovery, or the timing of completion of any legal proceedings or investigations. The Company continues to evaluate its liability assessment based on the accumulation of evidence expected to be obtained through continued discovery, expert testimony and opinion, and technical analysis.

Additionally, if BP discontinues payment or is otherwise unable to satisfy its obligations, the Company could be required to recognize a liability for OPA-related environmental costs. Similarly, if other identified RPs do not satisfy their obligations under OPA, the Company could incur additional liability. If Anadarko is required to recognize and pay additional liabilities, the Company could pursue remedies under the OA to recover costs from BP or the other party to the OA. In addition, the Company could pursue recovery or contribution from other parties or non-OA RPs.

Insurance Recoveries The Company carries insurance to protect against potential financial losses. At the time of the Deepwater Horizon events, the Company's insurance coverage applied to gross covered costs up to a level of approximately $710 million, less up to $60 million of deductibles. Based on Anadarko's 25% non-operated leasehold interest in the Lease, the Company estimates its potential net insurance coverage could total $178 million, less deductibles of $15 million. The Company has not recognized a receivable for any potential recoveries in its Consolidated Balance Sheets. At this time, recovery of these amounts is not considered probable because the Company is not considered to have incurred a probable loss under the OA or an insurable loss for unpaid liabilities. If the Company's current legal assessment changes such that the Company becomes liable under the OA for Deepwater Horizon event-related costs and funds such costs, the Company is positioned to recover the first $163 million of insured costs under its existing insurance policy. The Company also carries directors' and officers' insurance to cover certain risks associated with certain of the above-described legal proceedings.

3. Divestitures and Other

Gains (Losses) on Divestitures and Other In 2010, proceeds from divestitures, and net gains on such divestitures, of $70 million and $29 million, respectively, are primarily related to onshore United States oil and gas properties. During 2009 and 2008, the Company closed several unrelated property divestiture transactions, realizing proceeds of $176 million and $2.5 billion before income taxes, respectively, and net gains on divestitures of $44 million and $1.2 billion, respectively. The 2009 gains included $29 million related to divestitures of certain oil and gas properties in Qatar.

3. Divestitures and Other (Continued)

During 2008, the Company entered into an agreement to divest its 50% interest in the Peregrino field, offshore Brazil, and certain related assets. The Peregrino divestiture closed in December 2008. Anadarko received approximately $1.4 billion in net after-tax cash proceeds from the sale, recognizing a gain of approximately $800 million. In connection with the sale of its interest in the Peregrino field, Anadarko may receive up to $300 million of contingent consideration in future periods based on the value of oil produced from properties subject to the sale transaction. The Company has not recorded any amounts for this contingent consideration. Additionally, the Company has cash on deposit with the Brazilian federal court pending a decision regarding the rate of tax applicable to the sale of the Peregrino field.

The 2008 gains (losses) on divestitures and other, net include a net $82 million ($52 million after tax) reduction related to corrections resulting from analysis of property records after the adoption of the successful efforts method of accounting. This net amount includes a reduction of $163 million related to 2007. Management concluded that this misstatement was not material relative to 2007 interim and annual results, or to the 2008 periods, and corrected the error in the first quarter of 2008.

4. Inventories

The major classes of inventories, included in other current assets as of December 31, are as follows:

millions	**2010**	2009
Crude oil	**$ 126**	$ 97
Natural gas	**64**	94
NGLs	**61**	45
Total	**$ 251**	$ 236

5. Properties and Equipment

A summary of the cost of properties and equipment by function as of December 31, are as follows:

millions	**2010**	2009
Oil and gas [(1)]	**$ 48,328**	$ 44,328
Gathering, processing and marketing	**4,069**	3,705
Minerals	**1,187**	1,188
Other	**1,231**	1,123
Total	**$ 54,815**	$ 50,344

(1) Includes costs associated with unproved properties of $9.8 billion and $9.5 billion at December 31, 2010 and 2009, respectively.

5. Properties and Equipment (Continued)

At December 31, 2010, the Company has $3.0 billion and $337 million of unproved property acquisition costs and exploratory drilling costs, respectively, included in net properties and equipment on the Consolidated Balance Sheets related to properties in the Gulf of Mexico that were subject to the deepwater drilling moratoria issued by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). The moratoria were lifted October 12, 2010, but the BOEMRE has not approved new drilling permits. At December 31, 2010, no significant impairment of these properties had been recognized as a result of the moratoria and the Company intends to continue exploration and development of these properties. During the fourth quarter 2010, $46 million of exploratory drilling costs related to the Macondo well were charged to exploration expense. See Note 15.

During 2010, the Company recognized impairments of $147 million related to long-lived assets. These impairments include $114 million related to a production platform included in the oil and gas exploration and production operating segment that remains idle with no immediate plan for use, and for which a limited market currently exists. Other long-lived assets included in the oil and gas exploration and production operating segment were impaired by $31 million, which were primarily located in the Southern and Appalachia Region. Certain midstream operating segment assets were impaired by $2 million due to reduced operating activity. These assets were impaired to fair value, which was estimated using Level 3 inputs. Impairments and depreciation reduced the net book value of assets impaired during 2010 to $51 million at December 31, 2010.

During 2009, the Company recognized impairments of $41 million related to long-lived assets, including $22 million related to the oil and gas exploration and production operating segment triggered by the economic and commodity price environment, $7 million associated with certain gathering and processing facilities in the midstream operating segment due to reduced operating activity, and $12 million related to a liquefied natural gas facility site, included in the marketing operating segment. These assets were impaired to fair value, which was estimated using Level 3 inputs. Impairments and depreciation reduced the net book value of assets impaired in 2009 to $26 million at December 31, 2009.

During 2008, the Company recognized impairments of $211 million, including $113 million associated with properties in the United States included in the oil and gas exploration and production operating segment, and $98 million associated with certain gathering and processing facilities in the United States included in the midstream operating segment. These impairments resulted primarily from lower commodity prices at year-end 2008.

Suspended Exploratory Drilling Costs 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, 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 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, 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 drilling costs are expensed in that period.

5. Properties and Equipment (Continued)

The following table presents the amount of suspended exploratory drilling costs related to continuing operations at December 31 for each of the last three years, and changes to those amounts during the years then ended. The table excludes amounts capitalized and subsequently reclassified to proved oil and gas properties or charged to expense within the same year.

millions	**2010**	2009	2008
Balance at January 1	**$ 579**	$ 279	$ 308
Additions pending the determination of proved reserves	**491**	483	211
Reclassifications to proved properties	**(106)**	(120)	(175)
Charges to exploration expense	**(29)**	(63)	(65)
Balance at December 31	**$ 935**	$ 579	$ 279

The following table presents suspended exploratory drilling costs at December 31, 2010, by geographic area and by year of origination.

		Year Costs Incurred		
millions	**Total**	**2010**	**2009**	**2008 and prior**
United States—Onshore	$ 89	$ 75	$ 8	$ 6
United States—Offshore	275	76	125	74
International	571	313	186	72
	$ 935	$ 464	$ 319	$ 152
Suspended exploratory drilling costs capitalized for a period greater than one year after completion of drilling at December 31, 2010 (included in the table above)	$ 459			

Well costs that have been suspended for longer than one year are associated with 20 projects, primarily located in Brazil, Ghana and the Gulf of Mexico. The international projects with costs suspended for longer than one year are primarily suspended pending the results of additional appraisal activities and submission of a development plan. Management believes projects with suspended exploratory drilling costs exhibit sufficient quantities of hydrocarbons to justify potential development and is actively pursuing efforts to assess whether reserves can be attributed to the respective areas. The costs associated with deepwater Gulf of Mexico projects are suspended pending the completion of economic evaluations including, but not limited to, results of additional appraisal drilling, facilities, infrastructure, well-test analysis, additional geological and geophysical data, development plan approval, and permitting. 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.

6. Goodwill and Other Intangible Assets

Goodwill The Company tests goodwill for impairment annually at October 1, or more often as facts and circumstances warrant. The first step in the goodwill impairment test is to compare the fair value of each reporting unit to which goodwill has been assigned to the carrying amount of net assets, including goodwill, of the respective reporting unit. Anadarko has allocated goodwill to three reporting units: oil and gas exploration and production; gathering and processing; and transportation. During the second quarter of 2010, a decline in the fair value of Anadarko's oil and gas exploration and production reporting unit was indicated as a result of the Deepwater Horizon events and general uncertainty arising in connection with uncertain regulatory impacts associated with drilling in the deepwater Gulf of Mexico. See Note 2 and Note 15. The Company completed an interim goodwill impairment test of the oil and gas exploration and production reporting unit as of June 30, 2010, and the results of the test indicated no impairment.

At December 31, 2010, the Company had $5.3 billion of goodwill allocated to its three reporting units: $5.2 billion to oil and gas exploration and production; $134 million to gathering and processing; and $5 million to transportation. The Company completed its annual impairment assessment of goodwill during the fourth quarter of 2010, and the results of the test indicated no impairment.

Uncertainty related to the Deepwater Horizon events, difficulty or potential delays in obtaining drilling permits, significant declines in commodity prices, 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 subject to amortization at December 31, 2010 and 2009 and associated amortization expense for the years then ended are as follows:

millions	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Expense
December 31, 2010				
Offshore platform leases	**$ 60**	**$ (31)**	**$ 29**	**$ 3**
	$ 60	**$ (31)**	**$ 29**	**$ 3**
December 31, 2009				
Drilling contracts	$ 155	$ (155)	$ —	$ 2
Transportation contracts [(1)]	171	(163)	8	13
Offshore platform leases	60	(28)	32	2
	$ 386	$ (346)	$ 40	$ 17

(1) The carrying value of the transportation contracts was reduced to zero in 2010.

Drilling contract and offshore platform lease intangible assets are included in the Company's oil and gas exploration and production operating segment. Amortization of drilling contract intangibles is reflected in oil and gas properties as exploratory and development drilling costs, which are ultimately expensed through depletion or exploration expense. Drilling contract intangible value was fully amortized in 2009.

The Company recognized impairments related to certain transportation contracts included in intangible assets of $8 million and $74 million for 2010 and 2009, respectively, due to changes in price differentials at specific locations. These assets, included in the marketing operating segment, were impaired to fair value, determined using a discounted cash flow model incorporating market-based inputs representative of Level 2 inputs.

7. Noncontrolling Interests

Western Gas Partners, LP (WES), a consolidated subsidiary, is a limited partnership formed by Anadarko to own, operate, acquire and develop midstream assets. In 2010, WES issued approximately 13 million common units to the public, raising proceeds of $338 million, which were recorded as noncontrolling interests. In December 2009, WES issued approximately seven million common units to the public, raising proceeds of approximately $120 million, which were recorded as noncontrolling interests.

At December 31, 2010, the balance of noncontrolling interests on the Consolidated Balance Sheets includes approximately $143 million, net of tax, which will be transferred to paid-in capital if the WES subordinated limited partner units convert to common units. At December 31, 2010, Anadarko's ownership interest in WES consists of a 46.5% limited partner interest (common and subordinated units), a 2% general partner interest and incentive distribution rights.

8. Investments

Noncontrolling Mandatorily Redeemable Interests 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. At December 31, 2010, the carrying amount of these investments was $2.8 billion, while the carrying amount of notes payable to affiliates was $2.9 billion. 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 with the excess of the notes payable to affiliates over the aggregate investment carrying amounts reported 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 1.30% and 1.25% at December 31, 2010 and 2009, respectively. The note payable with the entity to which Anadarko contributed certain oil and gas properties contains a maximum 67% debt-to-capital covenant. Anadarko was in compliance with this covenant at December 31, 2010. Other (income) expense, net for 2010, 2009 and 2008, includes interest expense on the notes payable of $39 million, $57 million and $123 million, respectively, and equity earnings from Anadarko's investments in the investee entities of $(37) million, $(42) million and $(89) million, respectively.

Other During 2010, the Company's cost-method investment in Venezuelan assets was impaired to fair value, estimated using Level 3 inputs, recognizing impairment expense of $61 million ($23 million net of tax). At December 31, 2010 and 2009, the Company's after-tax net investment in these assets was $70 million and $83 million, respectively.

9. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability resulting 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 for oil. Basis swaps are used to fix or float the price differential between product prices at one market location versus another. Options are used to establish 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 (see Marketing and Trading Derivative Activities below).

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 Company does not apply hedge accounting to any of its derivative instruments. As a result, both realized and unrealized gains and losses associated with derivative instruments are recognized 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 economic transactions to which the derivatives relate are recorded to earnings.

Accumulated other comprehensive loss balances of $125 million ($79 million after tax) and $151 million ($96 million after tax) at December 31, 2010 and 2009, respectively, primarily relate to settled interest-rate derivatives that were previously designated as cash-flow hedges.

9. Derivative Instruments (Continued)

Oil and Natural-Gas Production/Processing Derivative Activities Below is a summary of the Company's derivative instruments at December 31, 2010, related to its oil and natural-gas production/processing. The natural-gas prices listed below are New York Mercantile Exchange (NYMEX) Henry Hub prices. The crude-oil prices listed below reflect a combination of NYMEX Cushing and London Brent Dated prices.

	2011	2012
Natural Gas		
Three-Way Collars (thousand MMBtu/d)	480	500
Average price per MMBtu		
Ceiling sold price (call)	$ 8.29	$ 9.03
Floor purchased price (put)	$ 6.50	$ 6.50
Floor sold price (put)	$ 5.00	$ 5.00
Fixed-Price Contracts (thousand MMBtu/d)	90	—
Average price per MMBtu	$ 6.17	$ —
Basis Swaps (thousand MMBtu/d)	45	—
Average price per MMBtu	$ (1.74)	$ —

MMBtu—million British thermal units
MMBtu/d—million British thermal units per day

	2011	2012
Crude Oil		
Three-Way Collars (MBbls/d)	126	2
Average price per barrel		
Ceiling sold price (call)	$ 99.95	$ 92.50
Floor purchased price (put)	$ 79.29	$ 50.00
Floor sold price (put)	$ 64.29	$ 35.00

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 In addition to the positions in the above tables, the Company also engages in marketing and trading activities, which include physical product sales and related derivative transactions used to manage commodity price risk. At December 31, 2010 and 2009, the Company had outstanding physical transactions related to natural gas for 32 billion cubic feet (Bcf) and 46 Bcf, respectively, offset by derivative transactions for 28 Bcf and 17 Bcf, respectively, for net positions of 4 Bcf and 29 Bcf, respectively.

9. Derivative Instruments (Continued)

Interest-Rate Derivatives In 2008 and 2009, Anadarko entered into interest-rate swap agreements to mitigate the risk of rising interest rates on up to $3.0 billion of debt originally expected to be refinanced in 2011 and 2012, over a reference term of either 10 years or 30 years. 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.

(Gains) losses on other derivatives, net for 2010 and 2009 includes unrealized (gains) losses of $284 million and $(57) million, respectively, and realized (gains) losses of zero and $(552) million, respectively, on these swap agreements. The realized gain in 2009 resulted from revising the contractual terms of this swap portfolio to increase the weighted-average interest rate from approximately 3.25% to approximately 4.80%.

A summary of the swaps outstanding at December 31, 2010, including the outstanding notional principal amounts and the associated reference periods, is presented below.

millions except percentages	Reference Period		Weighted-Average
Notional Principal Amount:	**Start**	**End**	**Interest Rate**
$ 750	October 2011	October 2021	4.72 %
$ 1,250	October 2011	October 2041	4.83 %
$ 250	October 2012	October 2022	4.91 %
$ 750	October 2012	October 2042	4.80 %

Effect of Derivative Instruments—Balance Sheet The fair value of all derivative instruments is included in the table below.

		Gross Derivative Assets		**Gross Derivative Liabilities**	
millions **Derivatives**	**Balance Sheet Classification**	**December 31, 2010**	December 31, 2009	**December 31, 2010**	December 31, 2009
Commodity					
	Other Current Assets	**$ 444**	$ 140	**$ (274)**	$ (63)
	Other Assets	**242**	82	**(56)**	(6)
	Accrued Expenses	**89**	195	**(131)**	(417)
	Other Liabilities	**26**	25	**(28)**	(52)
		801	442	**(489)**	(538)
Interest Rate and Other					
	Other Assets	**—**	53	**—**	—
	Accrued Expenses	**—**	—	**(190)**	—
	Other Liabilities	**—**	—	**(45)**	(3)
		—	53	**(235)**	(3)
Total Derivatives		**$ 801**	$ 495	**$ (724)**	$ (541)

9. Derivative Instruments (Continued)

Effect of Derivative Instruments—Statement of Income The unrealized and realized gain or loss amounts and classification related to derivative instruments for the respective years ended December 31 are as follows:

millions		(Gain) Loss		
Derivatives	**Classification of (Gain) Loss Recognized**	**Realized**	**Unrealized**	**Total**
2010				
Commodity	Gathering, Processing and Marketing Sales [(1)]	**$ 3**	**$ (4)**	**$ (1)**
	(Gains) Losses on Commodity Derivatives, net	**(498)**	**(395)**	**(893)**
Interest Rate and Other	(Gains) Losses on Other Derivatives, net	**—**	**285**	**285**
Derivative (Gain) Loss, net		**$ (495)**	**$ (114)**	**$ (609)**
2009				
Commodity	Gathering, Processing and Marketing Sales [(1)]	$ (2)	$ 39	$ 37
	(Gains) Losses on Commodity Derivatives, net	(327)	735	408
Interest Rate	(Gains) Losses on Other Derivatives, net	(525)	(57)	(582)
Derivative (Gain) Loss, net		$ (854)	$ 717	$ (137)
2008				
Commodity	Gathering, Processing and Marketing Sales [(1)]	$ 26	$ (29)	$ (3)
	(Gains) Losses on Commodity Derivatives, net	339	(900)	(561)
Interest Rate	(Gains) Losses on Other Derivatives, net	—	7	7
Derivative (Gain) Loss, net		$ 365	$ (922)	$ (557)

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

Credit-Risk Considerations The financial integrity of exchange-traded contracts is assured by NYMEX or the Intercontinental Exchange through systems of financial safeguards and transaction guarantees and is subject to nominal credit risk. Over-the-counter traded swaps, options and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its derivative counterparties, establishes credit limits according to the Company's credit policies and guidelines, and assesses the impact of a derivative counterparty's creditworthiness on fair value. The Company has the ability to require cash collateral or letters of credit to mitigate credit-risk exposure. The Company also routinely exercises its contractual right to net realized gains against realized losses when settling with derivative counterparties.

The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities. In addition, the Company has setoff agreements with certain financial institutions that are triggered in the event of default and provide for contract termination and net settlement across all derivative types. At December 31, 2010 and 2009, $394 million of the Company's $724 million gross derivative liability balance and $321 million of the Company's $541 million gross derivative liability balance, respectively, would be available, in the event of default, for setoff against the Company's gross derivative asset balance with financial institutions. Other than in the event of default, the Company does not net settle across commodity and interest-rate derivatives, as the timing of settlement differs.

9. Derivative Instruments (Continued)

Most of the Company's derivative instruments are subject to provisions that can require collateralization of the Company's obligations. In the event of a credit-rating downgrade to a level below investment grade by major credit rating agencies, the Company's counterparties may require immediate settlement or full collateralization. In June 2010, the Company's credit rating was downgraded from "Baa3" to "Ba1" by Moody's Investors Service (Moody's), which triggered credit-risk-related features with certain derivative counterparties, resulting in the Company posting additional collateral under its derivative instruments. No counterparties have requested termination or full settlement of derivative positions, and most of the Company's derivative counterparties already have a secured position in their capacity as lenders under a $5.0 billion senior secured revolving credit facility (the $5.0 billion Facility) discussed in Note 11, and, therefore, have agreed not to request additional financial assurance with respect to possible derivative liabilities. At December 31, 2010 and 2009, the aggregate fair value of all derivative instruments with credit-risk-related contingent features for which a net liability position existed was $9 million (net of collateral) and $146 million (net of collateral), respectively, included in accrued expenses on the Company's Consolidated Balance Sheets.

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. Because substantially all of the assumptions and inputs for industry-standard models are observable in active markets throughout the full term of the instruments, the inputs used to estimate fair value are categorized as Level 2 inputs.

The following tables set forth, by input level within the fair-value hierarchy, the fair value of the Company's derivative financial assets and liabilities.

December 31, 2010

millions	Level 1	Level 2	Level 3	Netting [1]	Collateral	Total
Assets:						
Commodity derivatives						
Financial institutions	$ 3	$ 557	$ —	$ (298)	$ (15)	$ 247
Other counterparties	—	241	—	(148)	—	93
Total derivative assets	$ 3	$ 798	$ —	$ (446)	$ (15)	$ 340
Liabilities:						
Commodity derivatives						
Financial institutions	$ (2)	$ (333)	$ —	$ 298	$ —	$ (37)
Other counterparties	—	(154)	—	148	—	(6)
Interest-rate and other derivatives	—	(235)	—	—	15	(220)
Total derivative liabilities	$ (2)	$ (722)	$ —	$ 446	$ 15	$ (263)

(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.

9. Derivative Instruments (Continued)

December 31, 2009

millions	Level 1	Level 2	Level 3	Netting [1]	Collateral [2]	Total
Assets:						
Commodity derivatives						
Financial institutions	$ 4	$ 385	$ —	$ (284)	$ —	$ 105
Other counterparties	—	53	—	(5)	—	48
Interest-rate derivatives	—	53	—	—	—	53
Total derivative assets	$ 4	$ 491	$ —	$ (289)	$ —	$ 206
Liabilities:						
Commodity derivatives						
Financial institutions	$ (6)	$ (520)	$ —	$ 284	$ 44	$ (198)
Other counterparties	—	(12)	—	5	—	(7)
Interest-rate derivatives	—	(3)	—	—	—	(3)
Total derivative liabilities	$ (6)	$ (535)	$ —	$ 289	$ 44	$ (208)

(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.

(2) Cash collateral held by counterparties from Anadarko was $105 million at December 31, 2009, including $61 million for which no net liability position existed at December 31, 2009. Anadarko held no cash collateral from counterparties at December 31, 2009.

10. Asset Retirement Obligations

The majority of Anadarko's AROs relate to the plugging and abandonment of oil and gas properties. The following table provides a rollforward of the Company's combined short and long-term AROs. Liabilities settled include settlement payments for obligations, as well as obligations that were assumed by purchasers of divested properties. Revisions to 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 settling AROs.

millions	**2010**	2009
Carrying amount of asset retirement obligations at January 1	**$ 1,446**	$ 1,368
Liabilities incurred	**88**	46
Liabilities settled	**(36)**	(54)
Accretion expense	**92**	89
Revisions in estimated liabilities	**(19)**	(3)
Carrying amount of asset retirement obligations at December 31 [1]	**$ 1,571**	$ 1,446

(1) At December 31, 2010 and 2009, short-term AROs of $42 million and $31 million, respectively, were presented in the Consolidated Balance Sheets as accrued expenses.

11. Debt and Interest Expense

Debt The following table presents the Company's outstanding debt and capital lease obligation at December 31, 2010 and 2009. See Note 8 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.

	December 31, 2010			December 31, 2009		
millions	**Principal**	**Carrying Value**	**Fair Value**	Principal	Carrying Value	Fair Value
6.750% Senior Notes due 2011	**$ —**	**$ —**	**$ —**	$ 950	$ 940	$ 1,004
6.875% Senior Notes due 2011	**285**	**287**	**296**	675	688	726
6.125% Senior Notes due 2012	**131**	**131**	**138**	170	169	180
5.000% Senior Notes due 2012	**39**	**39**	**40**	82	82	85
5.750% Senior Notes due 2014	**275**	**274**	**289**	275	274	296
7.625% Senior Notes due 2014	**500**	**499**	**561**	500	499	571
5.950% Senior Notes due 2016	**1,750**	**1,745**	**1,880**	1,750	1,744	1,893
6.375% Senior Notes due 2017	**2,000**	**2,000**	**2,179**	—	—	—
7.050% Debentures due 2018	**114**	**108**	**125**	114	108	120
6.950% Senior Notes due 2019	**300**	**297**	**334**	300	297	340
8.700% Senior Notes due 2019	**600**	**598**	**733**	600	598	749
6.950% Senior Notes due 2024	**650**	**672**	**706**	650	673	704
7.500% Debentures due 2026	**112**	**106**	**123**	112	106	115
7.000% Debentures due 2027	**54**	**54**	**55**	54	54	54
7.125% Debentures due 2027	**150**	**157**	**161**	150	157	152
6.625% Debentures due 2028	**17**	**17**	**17**	17	17	17
7.150% Debentures due 2028	**235**	**216**	**244**	235	215	233
7.200% Debentures due 2029	**135**	**135**	**138**	135	135	139
7.950% Debentures due 2029	**117**	**117**	**126**	117	117	127
7.500% Senior Notes due 2031	**900**	**858**	**995**	900	858	1,010
7.875% Senior Notes due 2031	**500**	**578**	**573**	500	580	583
Zero-Coupon Senior Notes due 2036	**2,360**	**607**	**704**	2,360	591	623
6.450% Senior Notes due 2036	**1,750**	**1,742**	**1,745**	1,750	1,742	1,827
7.950% Senior Notes due 2039	**325**	**324**	**372**	325	324	398
6.200% Senior Notes due 2040	**750**	**745**	**743**	—	—	—
7.730% Debentures due 2096	**61**	**61**	**61**	61	60	66
7.500% Debentures due 2096	**78**	**72**	**75**	78	72	74
7.250% Debentures due 2096	**49**	**49**	**46**	49	49	47
WES borrowings	**299**	**299**	**299**	—	—	—
Midstream subsidiary note payable to a related party	**—**	**—**	**—**	1,599	1,599	1,599
Total borrowings	**$ 14,536**	**$ 12,787**	**$ 13,758**	$ 14,508	$ 12,748	$ 13,732
Capital lease obligation	**226**	**226**	**N/A**	—	—	N/A
Less: Current portion of long-term debt	**289**	**291**	**296**	—	—	—
Total long-term debt	**$ 14,473**	**$ 12,722**	**$ 13,462**	$ 14,508	$ 12,748	$ 13,732

11. Debt and Interest Expense (Continued)

Carrying values in the table above include net unamortized debt discount of $1.7 billion and $1.8 billion at December 31, 2010 and 2009, respectively, which is amortized to interest expense over the terms of the related debt.

In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing Zero-Coupon Senior Notes (the Zero Coupons) maturing October 2036. The Zero Coupons have an aggregate principal amount due at maturity of $2.4 billion, reflecting a yield to maturity of 5.24%. The holder has the right to cause the Company to repay up to 100% of the then-accreted value of the Zero Coupons in October of each year starting in 2012.

All of the Company's outstanding debt is senior unsecured. WES's borrowings under its senior unsecured revolving credit facility (the RCF) and its senior unsecured term loan (the Term Loan) are not guaranteed by Anadarko or any of its wholly owned subsidiaries.

Debt Activity The following table presents the debt activity of the Company for 2010 and 2009.

millions	Principal	Carrying Value	Description
Balance at December 31, 2008	$ 14,120	$ 12,339	
Issuances	500	499	7.625% Senior Notes due 2014
	275	274	5.750% Senior Notes due 2014
	600	598	8.700% Senior Notes due 2019
	300	297	6.950% Senior Notes due 2019
	325	324	7.950% Senior Notes due 2039
Borrowings	100	100	WES credit facility
Repayments (1)	(1,420)	(1,420)	Floating-Rate Senior Notes due 2009
	(52)	(52)	7.300% Senior Notes due 2009
	(140)	(140)	Midstream Subsidiary Note due 2012
	(100)	(100)	WES credit facility
Other, net	—	29	Changes in debt premium or discount
Balance at December 31, 2009	$ 14,508	$ 12,748	
Issuances	**2,000**	**2,000**	6.375% Senior Notes due 2017
	750	**745**	6.200% Senior Notes due 2040
Borrowings	**670**	**670**	WES credit facility and term loan
Repayments (1)	**(950)**	**(942)**	6.750% Senior Notes due 2011
	(390)	**(398)**	6.875% Senior Notes due 2011
	(38)	**(38)**	6.125% Senior Notes due 2012
	(44)	**(43)**	5.000% Senior Notes due 2012
	(371)	**(371)**	WES credit facility
	(1,599)	**(1,599)**	Midstream Subsidiary Note due 2012
Other, net	**—**	**15**	Changes in debt premium or discount
Balance at December 31, 2010	**$ 14,536**	**$ 12,787**	

(1) Debt repayment activity includes both scheduled repayments and retirements before scheduled maturity by means of a tender offer, a call for redemption, or open-market purchases.

11. Debt and Interest Expense (Continued)

Capital Lease Obligation In the fourth quarter of 2010, a lease commenced for a floating production, storage and offloading vessel (FPSO) for the Company's Jubilee field operations in Ghana. The FPSO lease provides for an initial term of 10 years with annual renewal periods for an additional 10 years, annual purchase options that decrease over time and no residual value guarantees. The present value of the future minimum lease payments was determined to be greater than the fair value of the FPSO, resulting in recognition of the capital lease asset and the associated obligation of $226 million for the Company's approximate 26% working interest share of the fair value of the FPSO. The capital lease asset will be depreciated over the estimated proved reserves of the Jubilee field using the UOP method. At December 31, 2010, future minimum lease payments are $37 million for 2011, $38 million for 2012, $37 million for 2013, $38 million for 2014, $37 million for 2015 and $461 million thereafter.

Midstream Subsidiary Note Payable to a Related Party In 2007, Anadarko, and an entity formed by a group of unrelated third-party investors (the Investor), formed Trinity Associates LLC (Trinity), a variable interest entity. Trinity was initially capitalized with a $100 million cash contribution by Anadarko in exchange for Class A member and managing member interests in Trinity, and a $2.2 billion cash contribution by the Investor in exchange for a Class B member cumulative preferred interest. Trinity invested $100 million in a United States Government securities money market fund (the Fund) and loaned $2.2 billion to a wholly owned midstream subsidiary of Anadarko (Midstream Holding). The outstanding balance, described in the accompanying Consolidated Balance Sheets as Midstream Subsidiary Note Payable to a Related Party (Midstream Subsidiary Note), was repaid in full in 2010.

Proceeds from repayment of the Midstream Subsidiary Note were distributed by Trinity to the Investor. Proceeds from Trinity's liquidation of its investment in the Fund were distributed to Anadarko. Anadarko accounted for its investment in Trinity using the equity method of accounting, and the $100 million distribution received reduced the carrying amount of that investment to zero.

Anadarko Revolving Credit Facility In September 2010, the Company entered into the $5.0 billion Facility, and terminated its $1.3 billion revolving credit agreement, scheduled to mature in 2013. At December 31, 2010, the $5.0 billion Facility was undrawn with available capacity of $4.6 billion ($5.0 billion undrawn capacity less $377 million in outstanding letters of credit).

Borrowings under the $5.0 billion Facility will bear interest, at the Company's election, at (i) LIBOR plus a margin ranging from 2.75% to 3.75%, based on the Company's credit rating, or (ii) the greatest of (a) the JPMorgan Chase Bank prime rate, (b) the federal funds rate plus 0.50%, or (c) one-month LIBOR plus 1%, plus in each case, an applicable margin.

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 9), 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. 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. The Company was in compliance with all applicable covenants at December 31, 2010, and there were no restrictions on its ability to utilize the available capacity of the $5.0 billion Facility.

11. Debt and Interest Expense (Continued)

WES Revolving Credit Facility At December 31, 2010, the WES RCF had outstanding borrowings of $49 million, with $401 million of available borrowing capacity. The RCF matures in October 2012 and bears interest at LIBOR plus an applicable margin ranging from 2.375% to 3.250%, for a rate of 3.26% at December 31, 2010.

WES Term Loan In August 2010, WES borrowed $250 million under the Term Loan, which matures in 2013, from a group of banks. The Term Loan bears interest at LIBOR plus an applicable margin ranging from 2.50% to 3.50% (for a rate of 3.26% at December 31, 2010) depending on WES's Consolidated Leverage Ratio, as defined in the agreement governing the Term Loan.

Scheduled Maturities Total principal amount of debt maturities for the five years ending December 31, 2015, are shown below, including payments on the Company's capital lease obligation, and excluding any amounts attributable to the potential repayment of the Zero Coupons that may be put to the Company annually, starting in 2012, as discussed above.

millions	**Principal Amount of Debt Maturities**
2011	$ 289
2012	223
2013	255
2014	781
2015	6

Interest Expense The following table summarizes the amounts included in interest expense.

	Years Ended December 31,		
millions	**2010**	2009	2008
Current debt, long-term debt and other [1]	**$ 856**	$ 734	$ 762
Midstream subsidiary note payable to a related party	**24**	39	109
(Gain) loss on early debt retirements and commitment termination	**103**	(2)	(16)
Capitalized interest	**(128)**	(69)	(123)
Interest expense	**$ 855**	$ 702	$ 732

(1) Included in 2009 is the reversal of the $78 million liability for unpaid interest related to the DWRRA dispute. See Note 15.

12. Stockholders' Equity

Common Stock In August 2008, the Company initiated a $5 billion share-repurchase program (the Program) under which shares may be repurchased either in the open market or through privately negotiated transactions. The Program is authorized to extend through August 2011, does not obligate Anadarko to acquire any specific number of shares and may be discontinued at any time. During 2008, Anadarko purchased 10 million shares of common stock for $600 million under the Program through purchases in the open market and under share-repurchase agreements. During 2010 and 2009, no shares were repurchased under the Program.

In May 2009, Anadarko completed a public offering of 30 million shares of common stock at $45.50 per share. After deducting the underwriting discount and other offering costs of $28 million, net proceeds to the Company were approximately $1.3 billion, and were used for general corporate purposes, including capital expenditures.

millions	**2010**	2009	2008
Shares of common stock issued			
Shares at January 1	**509**	476	473
Issuance of common stock	—	30	—
Exercise of stock options	**2**	1	1
Issuance of restricted stock	**2**	2	2
Shares at December 31	**513**	509	476
Shares of common stock held in treasury			
Shares at January 1	**16**	16	5
Purchase of treasury stock	—	—	10
Shares received for restricted stock vested	**1**	—	1
Shares at December 31	**17**	16	16
Shares of common stock outstanding at December 31	**496**	493	460

The number of shares of common stock issued and shares of common stock held in treasury presented in the table above includes four million shares held by the Anadarko Petroleum Corporation Executives and Directors Benefits Trust, a grantor trust associated with the Company's obligations under certain of its pension and deferred-compensation plans.

12. Stockholder's Equity (Continued)

The reconciliation between basic and diluted EPS from continuing operations attributable to common stockholders is as follows:

	Years Ended December 31,		
millions except per-share amounts	**2010**	2009	2008
Income (loss):			
Income (loss) from continuing operations attributable to common stockholders	**$ 761**	$ (135)	$ 3,197
Less: Distributions on participating securities	**1**	—	2
Less: Undistributed income allocated to participating securities	**4**	—	37
Basic	**$ 756**	$ (135)	$ 3,158
Diluted	**$ 756**	$ (135)	$ 3,158
Shares:			
Basic			
Weighted-average common shares outstanding	**495**	480	465
Dilutive effect of stock options and performance-based stock awards	**2**	—	1
Diluted	**497**	480	466
Excluded [(1)]	**6**	14	8
Income (loss) per common share:			
Basic	**$ 1.53**	$ (0.28)	$ 6.79
Diluted	**$ 1.52**	$ (0.28)	$ 6.78
Dividends per common share	**$ 0.36**	$ 0.36	$ 0.36

(1) Inclusion of the average shares for these awards would have had an anti-dilutive effect.

Preferred Stock In the second quarter of 2008, Anadarko redeemed and subsequently retired its 5.46% Series B Cumulative Preferred Stock for $45 million. Holders of the shares were entitled to receive, when and as declared by the Board of Directors, cumulative cash dividends at an annual rate of $5.46 per share.

Dividends of $27.30 per share for the related portion of 2008 (equivalent to $2.73 per Depositary Share) were paid to holders of preferred stock.

13. Share-Based Compensation

At December 31, 2010, 20 million shares of the 35 million shares of Anadarko common stock originally authorized for awards under the active share-based compensation plans remain available for future issuance. The Company generally issues new shares to satisfy employee share-based payment plans. The number of shares available is reduced by awards granted. A summary of share-based compensation cost is presented below.

millions	Years Ended December 31, 2010	2009	2008
Compensation Cost:			
Equity-Classified Awards:			
Restricted stock	$ **103**	$ 138	$ 131
Stock options	**45**	36	19
Performance-based share awards and other	**3**	11	18
Total Equity-Classified Award Compensation Expense	**151**	185	168
Liability-Classified Awards:			
Value Creation Plan	**—**	104	4
Performance-based unit awards	**36**	17	1
Other	**10**	3	1
Total Liability-Classified Award Compensation Expense	**46**	124	6
Total Compensation Expense, pretax	$ **197**	$ 309	$ 174
Income tax benefit	$ **72**	$ 112	$ 63

For 2010, 2009 and 2008, $26 million, $12 million and $9 million, respectively, in excess tax benefits were included in cash flows from financing activities. Cash received from stock option exercises for 2010, 2009 and 2008 was $78 million, $22 million and $14 million, respectively.

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 receive cash dividend equivalents during the restriction period and do not have the right to vote the units. Restricted stock vests over service periods ranging from the date of grant up to four years and is not considered issued and outstanding until it vests.

Nonemployee directors are granted deferred shares that are held in a grantor trust by the Company until payable, generally when the director ceases to serve on the Board of Directors. Directors may receive these shares in a lump-sum payment, or in annual installments.

13. Share-Based Compensation (Continued)

A summary of restricted stock activity for the year ended December 31, 2010, is presented below.

	Shares *(millions)*	**Weighted-Average Grant-Date Fair Value**
Nonvested at January 1, 2010	3.83	$ 50.98
Granted	0.83	$ 69.47
Vested	(1.77)	$ 51.08
Forfeited	(0.11)	$ 51.32
Nonvested at December 31, 2010	2.78	$ 56.39

The weighted-average grant-date fair value of restricted stock granted during 2009 and 2008 was $40.65 and $61.20, respectively. The total fair value of restricted shares vested during 2010, 2009 and 2008 was $105 million, $122 million and $110 million, respectively, based on the market price at the vesting date. At December 31, 2010, $94 million of total unrecognized compensation cost related to restricted stock is expected to be recognized over a weighted-average remaining service period of 1.9 years.

Stock Options Certain employees may be granted 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 service periods ranging from three to four years from the date of grant and will terminate at the earlier of the date of exercise, or seven years from the date of grant.

Nonemployee directors may be granted nonqualified stock options with an exercise price equal to the fair market value of Anadarko common stock on the date of grant. These stock options vest over a one-year service period from the date of grant and terminate at the earlier of the date of exercise, or ten 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 the option is estimated based on historical exercise behavior. The expected forfeiture rate is estimated based on historical forfeiture experience. The volatility assumption is estimated based on expectations of volatility over the life of the option as indicated by historical and implied volatility. The risk-free interest rate is based on the U.S. Treasury rate for a term commensurate with the expected life of the 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 the option. The Company used the following weighted-average assumptions to estimate the fair value of stock options granted during 2010, 2009 and 2008.

	2010	2009	2008
Expected option life—years	**4.9**	4.9	4.9
Volatility	**43.9%**	46.3%	37.3%
Risk-free interest rate	**2.0%**	1.9%	2.5%
Dividend yield	**0.7%**	0.8%	0.6%

13. Share-Based Compensation (Continued)

A summary of stock option activity for the year ended December 31, 2010, is presented below.

	Shares *(millions)*	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term *(years)*	Aggregate Intrinsic Value *(millions)*
Outstanding at January 1, 2010	9.48	$ 42.01		
Granted	2.30	$ 69.34		
Exercised	(2.04)	$ 38.44		
Forfeited or expired	(0.19)	$ 51.72		
Outstanding at December 31, 2010	9.55	$ 49.15	4.95	$ 257.8
Vested or expected to vest at December 31, 2010	9.36	$ 49.14	4.94	$ 253.0
Exercisable at December 31, 2010	4.18	$ 45.84	4.00	$ 126.8

The weighted-average grant-date fair value of stock options granted during 2010, 2009 and 2008 was $26.44, $15.23 and $13.93, respectively, using the Black-Scholes option-pricing model. The total intrinsic value of stock options exercised during 2010, 2009 and 2008 was $62 million, $24 million and $13 million, respectively, based on the difference between the market price at the exercise date and the exercise price. At December 31, 2010, $78 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of 2.0 years.

Performance-Based Share Awards In November 2007, two Performance Unit Award Agreements were entered into with certain officers. The number of shares of common stock awarded under these agreements is based solely on a comparison of the Company's TSR to the TSR of a predetermined group of peer companies over performance periods ranging from one to three years. The table below summarizes these awards.

Year Granted	Award Type	Maximum Shares of Common Stock	Performance Period	Shares of Common Stock Issued	Year Issued
2007	Transitional	184,512	1.1.2008—12.31.2008	6,162 (1)	2008
		184,512	1.1.2008—12.31.2009	7,719 (1)	2009
				128,505 (2)	2010
	Annual	282,700	1.1.2008—12.31.2009	5,700 (1)	2008
				125,706 (2)	2010
		282,700	1.1.2008—12.31.2010	29,100 (1)	2009
				83,682 (3)	2011

(1) No shares of common stock were issued to current officers. Shares shown as issued reflect shares issued to certain officers whose employment with the Company terminated prior to the end of the performance period and the determination of actual performance.
(2) During 2010, 336,865 shares were awarded to current officers for the performance period that ended December 2009.
(3) During 2011, 135,712 shares were awarded to current officers for the performance period that ended December 2010.

13. Share-Based Compensation (Continued)

Liability-Classified Awards

Value Creation Plan As a part of its employee compensation program, the Company offers an incentive compensation program that generally 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. At December 31, 2010, 2009 and 2008, the Company had accrued zero, $105 million and zero, respectively, for the 2010, 2009 and 2008 performance periods, respectively.

Performance-Based Unit Awards In November of 2008, 2009 and 2010, certain officers of the Company were provided Performance Unit Award Agreements with a two-year performance period ending December 31, 2010, 2011 and 2012, respectively, and a three-year performance period ending December 31, 2011, 2012 and 2013, respectively. The vesting of these units is based solely 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, will be paid in cash. At December 31, 2010, the liability under Performance Unit Award Agreements was $53 million, with $42 million of total estimated unrecognized compensation cost related to these awards expected to be recognized over a weighted-average, remaining performance period of 1.7 years.

14. Commitments

Operating Leases The Company has $1.4 billion in long-term drilling rig commitments that satisfy operating lease criteria. The Company also has various commitments under noncancelable operating lease agreements of $766 million for production platforms and equipment, buildings, facilities, compressors and aircraft. These operating leases expire at various dates through 2024. Certain of these operating leases contain residual value guarantees at the end of the lease term, totaling $96 million at December 31, 2010; however, no liability has been accrued for residual value guarantees. At December 31, 2010, future minimum lease payments under existing operating leases are as follows:

millions	Operating Leases
2011	$ 727
2012	641
2013	364
2014	98
2015	67
Later years	238
Total future minimum lease payments [(1)]	$ 2,135

(1) Total future minimum lease payments have not been reduced for future sublease income of $ 11 million.

Total rent expense, net of sublease income, amounted to $154 million in 2010, $188 million in 2009 and $226 million in 2008. Total rent expense includes contingent rent expense related to processing fees of $20 million, $39 million and $32 million in 2010, 2009 and 2008, respectively.

14. Commitments (Continued)

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 approximately $1.3 billion related to three offshore drilling vessels and $119 million related to certain contracts for onshore United States drilling rigs. Lease payments associated with 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 in future periods or written off as exploration expense. These minimum lease payments do not include amounts related to idle rig costs for two of the four rigs for which the Company has declared force majeure. See Note 15 for information on drilling rig commitments where the Company declared force majeure and canceled the related contracts.

Production Platforms The table of future minimum lease payments above includes $39 million related to the monthly demand charges due under agreements with third parties for the dedication, processing and gathering of natural-gas and condensate production from several natural-gas fields in the deepwater Gulf of Mexico. The agreements do not contain any purchase options, purchase obligations or value guarantees.

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 $423 million for these agreements. These agreements also contain residual value guarantees totaling $37 million at the end of the lease periods.

Other Commitments In the normal course of business, the Company enters into other contractual agreements to purchase natural gas or crude oil, pipeline capacity, storage capacity, utilities and other services. Aggregate future payments under these contracts total $4.0 billion, of which $1.2 billion is expected to be paid in 2011, $782 million in 2012, $484 million in 2013, $305 million in 2014, $179 million in 2015 and $1.1 billion thereafter.

Sale of Future Hard Minerals Royalty Revenues In 2004, the Company conveyed a limited-term non-participating royalty interest, which was carved out of the Company's existing royalty interests, that entitles a third party to receive future coal and trona royalty revenue over an 11-year period. The Company retains 100% of the aggregate royalty payment receipts between $229 million and $400 million during the term of the agreement and 95% of the aggregate royalty payment receipts that are in excess of $400 million during the first ten years of the agreement. The specified cumulative future amount that the third-party investor expects to receive, prior to the 5% of any excess royalties described above, is $76 million. This amount and the payment timing are subject to change based on the actual royalties received by the Company during the term of the agreement. The third party relies solely on royalty payments to recover its investment; therefore, the third party bears the risk associated with the royalties being insufficient to recover the original investment over the term of the agreement.

Proceeds from this transaction were accounted for as deferred revenues and classified as liabilities on the balance sheet. The deferred revenues are amortized to other sales on a unit-of-revenue basis over the term of the agreement. For each of the years 2010, 2009 and 2008, the Company amortized $16 million of deferred revenues to other sales revenues related to this agreement. At December 31, 2010, the balance of deferred revenue to be recognized in future periods is $48 million.

15. Contingencies

The following discussion of the Company's contingencies excludes discussion related to the Deepwater Horizon events. See Note 2 Deepwater Horizon Events.

General Litigation charges and adjustments of $10 million increased income before income taxes, and $24 million and $112 million decreased income before income taxes during 2010, 2009 and 2008, respectively. The Company is a defendant in a number of lawsuits and is involved in governmental proceedings arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims and environmental claims. The Company has also been named as a defendant in various personal injury claims, including claims by employees of third-party contractors alleging exposure to asbestos, silica and benzene while working at refineries previously owned by acquired companies. While the ultimate outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Litigation The Company is subject to various claims by its royalty owners in the regular course of business as an oil and gas producer, including disputes regarding measurement, post-production costs and expenses, and royalty valuations. The Company and Kerr-McGee Corporation (Kerr-McGee) were named as a defendants in a case styled *U.S. of America ex rel. Harrold E. Wright v. AGIP Petroleum Co., et al.* filed in September 2000 in the United States District Court for the Eastern District of Texas, Lufkin Division. This lawsuit generally alleges that the Company, including Kerr-McGee, and other industry defendants knowingly undervalued natural gas in connection with royalty payments on production from federal and Indian lands. Based on the Company's present understanding of these various governmental and False Claims Act proceedings, the Company believes that it has substantial defenses to these claims and is vigorously asserting such defenses. However, if the Company is found to have violated the False Claims Act, the Company could be subject to a variety of damages, including treble damages and substantial monetary fines. The claims against the Company have not been set for trial. The Company has reached a tentative settlement with the United States Government and the Relators, which, if finalized, will resolve this litigation against Anadarko and Kerr-McGee, as well as several administrative actions. The tentative settlement must be approved by various levels of authority within the United States Government, which could take up to a year. Management has accrued a liability for the estimated settlement amount. The Company believes that an additional loss, in excess of the accrued settlement amount, is unlikely to have a material adverse effect on Anadarko's consolidated financial position, results of operations or cash flows.

In January 2009, Tronox Incorporated (Tronox), a former wholly owned subsidiary of Kerr-McGee, and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of New York (the Court). Subsequently, in May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee asserting a number of claims, including claims for actual and constructive fraudulent conveyance (the Adversary Proceeding). Tronox alleges, among other things, that it was insolvent or undercapitalized at the time it was spun off from Kerr-McGee. Tronox seeks, among other things, to recover an unspecified amount of damages, including interest, from Kerr-McGee and Anadarko as well as the litigation fees and costs. In addition, Tronox seeks to equitably subordinate and/or disallow all claims asserted by Anadarko and Kerr-McGee in the bankruptcy cases. Anadarko and Kerr-McGee moved to dismiss the complaint in its entirety. In March 2010, the Court issued an opinion granting in part and denying in part Anadarko's and Kerr-McGee's motion to dismiss the complaint. Notably, the Court dismissed, with prejudice, Tronox's request for punitive damages relating to the fraudulent conveyance claims. The Court granted Tronox leave to replead certain of its common law claims, and Tronox filed an amended complaint in April 2010. Anadarko and Kerr-McGee have moved to dismiss three breach of fiduciary duty-related claims in the amended complaint. That motion has been briefed and is awaiting a ruling by the Court. The Adversary Proceeding is set for trial in March 2012.

15. Contingencies (Continued)

The United States filed a motion to intervene in the Adversary Proceeding, asserting that it has an independent cause of action against Anadarko, Kerr-McGee and Tronox under the Federal Debt Collection Procedures Act relating primarily to environmental cleanup obligations allegedly owed to the United States by Tronox. That motion to intervene has been granted, and the United States is now a co-plaintiff against Anadarko and Kerr-McGee in the Adversary Proceeding. Anadarko and Kerr-McGee have moved to dismiss the United States' complaint-in-intervention, but that motion currently has been stayed by order of the Court.

In June 2010, Anadarko and Kerr-McGee filed a motion in Tronox's Chapter 11 cases to compel Tronox to assume or reject the Master Separation Agreement (together with all annexes, related agreements, and ancillary agreements to it, the MSA). In response to this motion, Tronox announced to the Court that it would reject the MSA effective July 22, 2010. In August 2010, the Court entered a Stipulation and Agreed Order among Tronox, Anadarko, and Kerr-McGee authorizing the rejection of the MSA.

During 2010, the Company reversed a $95 million liability for a reimbursement obligation that was provided by Kerr-McGee to Tronox pursuant to the terms of the MSA. Following Tronox's rejection of the MSA, Anadarko and Kerr-McGee filed amended proofs of claim (the Proofs of Claim), which include claims for damages arising from such rejection of the MSA. Tronox and several of its creditors have objected to the Proofs of Claim. At the end of January 2011, the Court entered a Stipulation and Agreed Order regarding a settlement of the claims by Anadarko and Kerr-McGee against Tronox resulting from its rejection of the MSA. In February 2011, the Company received its agreed-upon claim, in the form of Tronox equity, valued at $29 million.

The Company will continue to monitor events subsequent to the MSA rejection and will assess the impact of future events on the Company's consolidated financial position, results of operations or cash flows. See *Guarantees and Indemnifications* section of this Note 15.

In August 2010, Tronox filed a motion seeking, among other things, (i) authority to enter into a certain plan support agreement and equity-commitment agreement (together, the Plan Support Agreements) and (ii) approval of procedures for a rights offering. Anadarko and Kerr-McGee filed an objection to the motion. In the objection, Anadarko and Kerr-McGee requested that the Court order mediation of the Adversary Proceeding. Tronox and the United States opposed mediation, citing, in support of their position, a lack of sufficient discovery. The Court declined to order mediation at that time. In September 2010, the Court entered an order authorizing Tronox to enter into the Plan Support Agreements and approved the rights offering procedures. Anadarko and Kerr-McGee are not subject to the rights offering procedures. However, Anadarko and Kerr-McGee reached an agreement with Tronox that will entitle them to receive the economic benefit on account of their claims against Tronox as if they had participated in the rights offering if certain conditions are satisfied.

In September 2010, Tronox filed a Proposed First Amended Joint Plan of Reorganization pursuant to Chapter 11 of the Bankruptcy Code (the Plan) and a related disclosure statement (the Disclosure Statement), which modify and supersede the terms of its plan and disclosure statement filed in July 2010. Tronox subsequently filed further amendments to the Plan and Disclosure Statement. The Plan contemplates, among other things, that (a) the claims of the United States (as well as other federal, state, local or tribal governmental entities having regulatory authority or responsibilities with respect to environmental laws) related to Tronox's environmental liabilities at legacy sites, will be settled through the creation of certain environmental response trusts and a litigation trust, to which Tronox will contribute the following consideration: (i) $270 million in cash, (ii) 88% of the proceeds from the Adversary Proceeding, (iii) certain Nevada assets, including the real property located in Henderson, Nevada, (iv) certain other real property and related assets, and (v) certain insurance and financial assurance assets worth at least $50 million; (b) certain creditors who have asserted tort claims against Tronox arising from, among other things, environmental contamination or chemical or asbestos exposure will receive the following consideration from a trust to be created under the Plan: (i) $13 million in cash, (ii) 12% of the proceeds from the Adversary Proceeding, and (iii) certain insurance assets, including the net proceeds of certain insurance settlements; and (c) certain creditors who have asserted general unsecured claims against Tronox will receive the following consideration: (i) their pro rata share of 50.9% of the common equity of reorganized Tronox and (ii) the right to purchase up to 45.5% of the common equity of reorganized Tronox. Objections to the Plan and Disclosure Statement were filed by various interested parties, including Anadarko and Kerr-McGee.

15. Contingencies (Continued)

In October and November 2010, Tronox filed certain documents central to the Plan as part of the Plan Supplement including, among other things, the Environmental Claims Settlement Agreement and the Tort Claims Trust Agreement. The Plan contemplates that additional documents, including the Anadarko Litigation Trust Agreement, will be filed as part of the Plan Supplement and parties in interest will have an opportunity to object to those documents before they become effective pursuant to the Plan. Also in November 2010, the Court confirmed the Plan, subject to certain modifications and settlements, and entered the order confirming the Plan. Anadarko's objections to the Plan were resolved prior to confirmation. In February 2011, Tronox emerged from bankruptcy. It is unclear what, if any, effect the Plan might have on the Adversary Proceeding or its outcome.

In addition, a consolidated class action complaint has been filed in the United States District Court for the Southern District of New York (the District Court) on behalf of purported purchasers of Tronox's equity and debt securities between November 21, 2005, and January 12, 2009 (the Class Period), against Anadarko, Kerr-McGee, several former Kerr-McGee officers and directors, several former Tronox officers and directors and Ernst & Young LLP. The complaint alleges causes of action arising under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 (the Exchange Act) for purported misstatements and omissions regarding, among other things, Tronox's environmental-remediation and tort claim liabilities. The plaintiffs allege, among other things, that these purported misstatements and omissions are contained in certain of Tronox's public filings, including filings made in connection with Tronox's initial public offering. The plaintiffs seek an unspecified amount of compensatory damages, including interest thereon, as well as litigation fees and costs. Anadarko, Kerr-McGee and other defendants moved to dismiss the class action complaint and in June 2010, the District Court issued an opinion and order dismissing the plaintiffs' complaint against Anadarko, but granted the plaintiffs leave to replead their allegations related to the claim that Anadarko was liable as a successor-in-interest to Kerr-McGee. The District Court further granted in part and denied in part the motions to dismiss by Kerr-McGee and certain of its former officers and directors, but permitted the plaintiffs leave to replead certain of the dismissed claims. The plaintiffs filed an amended consolidated class action complaint in July 2010. In August 2010, Anadarko, Kerr-McGee, and several of Kerr-McGee's former officers and directors filed respective motions to dismiss. In January 2011, the District Court issued an opinion and order denying the motions of Kerr-McGee and several former Kerr-McGee officers and directors. The District Court also denied Anadarko's motion to dismiss the remaining Section 20(a) claim under the Exchange Act covering the period beginning on August 10, 2006, through the end of the alleged Class Period. However, the District Court dismissed this claim against Anadarko to the extent it was based on a successor-in-interest theory of liability. The discovery process is ongoing.

The Tronox proceedings are at a very early stage; accordingly, the Company currently cannot assess the probability of losses, or reasonably estimate a range of any potential losses related to the proceedings described above. The Company intends to vigorously defend itself, its officers and its directors in these proceedings.

Deepwater Drilling Moratorium and Other Related Matters In May and July 2010, the BOEMRE, previously known as the Minerals Management Service (MMS), an agency of the Department of the Interior (DOI), issued directives requiring lessees and operators of federal oil and gas leases in the Outer Continental Shelf regions of the Gulf of Mexico and Pacific Ocean to cease drilling all new deepwater wells, including wellbore sidetracks and bypasses, through November 30, 2010. These deepwater drilling moratoria (collectively, the Moratorium) prohibited drilling and/or spudding any new wells, and required operators that were in the process of drilling wells to proceed to the next safe opportunity to secure such wells, and to take all necessary steps to cease operations and temporarily abandon the impacted wells. Anadarko ceased all drilling operations in the Gulf of Mexico in accordance with the Moratorium, which resulted in the suspension of operations of two operated deepwater wells (Lucius and Nansen) and one non-operated deepwater well (Vito). The Moratorium was lifted effective October 12, 2010, but the BOEMRE has not approved new drilling permits.

15. Contingencies (Continued)

As a result of the Moratorium and additional inspection and safety requirements issued by the BOEMRE, in May and June 2010, the Company provided notification of force majeure to drilling contractors of four of the Company's contracted deepwater rigs in the Gulf of Mexico. Some of the contracts have provisions that authorize contract termination by either party if force majeure conditions continue for a specified number of consecutive days.

In June 2010, the Company gave written notice of termination to the drilling contractor of a rig placed in force majeure in May 2010, and filed a lawsuit in the United States District Court for the Southern District of Houston against the drilling contractor seeking a judicial declaration that the Company's interpretation of the drilling contract was correct and that the contract terminated on June 19, 2010. The drilling contractor filed an Original Answer in July 2010 denying the Moratorium constituted a force majeure event and asserted that Anadarko had breached the drilling contract. If the Company does not prevail in its claim, the Company could be obligated to pay the rig contract rate from the contract-termination date through March 2011, the end of the original contract term.

In September 2010, the Company gave written notice of termination to another drilling contractor of a rig that had been placed in force majeure, and the Company filed a lawsuit in the United States District Court for the Southern District of Houston against the drilling contractor seeking a judicial declaration that the Company's interpretation of the drilling contract was correct and that the contract terminated on September 18, 2010. The drilling contractor filed a Motion to Dismiss and an Original Answer in October 2010. The court, acting on its discretion, converted the Motion to Dismiss into a Motion for Summary Judgment and entered a scheduling order for submission of briefs during February and March 2011. If the Company does not succeed in its claim, the Company could be obligated to pay the rig contract rate from the contract-termination date through March 2013, the end of the original contract term.

The disputed rentals for the contract periods described above are \$90 million and \$377 million, respectively, but any potential damages would be reduced by, among other things, any amounts resulting from the drilling contractor's ability to mitigate damages by leasing the drilling rig to another third party, as well as cost savings incurred by the drilling contractor by not having to operate the drilling rig on a daily basis. At December 31, 2010, the Company has not recorded a liability for costs associated with these disputes as management believes payment related to these matters is not probable. The Company intends to vigorously pursue each claim.

In September 2010, the BOEMRE issued a Notice to Lessees that requires lessees to plug all wells that have been idle for the past five years and decommission related equipment. Lessees were required to submit a company-wide plan for decommissioning facilities and wells. Anadarko completed this plan and does not believe the costs to implement the plan will have a material impact on the Company's consolidated financial position, results of operations or cash flows.

Deepwater Royalty Relief Act In 1995, the United States Congress passed the Deepwater Royalty Relief Act (DWRRA) to stimulate exploration and production of oil and natural gas by providing relief from the obligation to pay royalties on certain federal leases located in the deep waters of the Gulf of Mexico. The Company currently owns interests in several deepwater Gulf of Mexico leases. After the passage of the DWRRA, the MMS (renamed the BOEMRE as discussed above) inserted price thresholds into leases issued in 1996, 1997 and 2000 that effectively eliminated the DWRRA royalty relief if these price thresholds were exceeded.

In January 2006, the DOI issued an order (the 2006 Order) to Kerr-McGee Oil and Gas Corporation (KMOG), a subsidiary of Kerr-McGee, to pay oil and gas royalties and accrued interest on KMOG's deepwater Gulf of Mexico production associated with eight 1996, 1997 and 2000 leases, for which KMOG considered royalties to be suspended under the DWRRA. KMOG successfully appealed the 2006 Order, and the DOI's petition for a writ of certiorari with the United States Supreme Court was denied on October 5, 2009.

15. Contingencies (Continued)

In 2009, based on the U.S. Supreme Court's denial of the DOI's petition for review by the court, Anadarko reversed its $657 million liability for accrued royalties on leases listed in the 2006 Order, similar orders to pay issued in 2008 and 2009, and other deepwater Gulf of Mexico leases with similar price-threshold provisions. The Company's accrued liability of $657 million related to royalties on production from January 2003 through September 2009, including a $165 million liability related to pre-acquisition contingencies recorded in purchase accounting. In addition, the Company reversed its $78 million accrued liability for interest on these unpaid royalty amounts, substantially all of which related to post-acquisition periods.

The MMS issued two additional orders to Anadarko in 2008 and 2009 to pay "past-due" royalties and interest covering several deepwater Gulf of Mexico leases. Anadarko filed administrative appeals with the MMS for the 2008 and 2009 orders (which were stayed pending a final non-appealable judgment relating to the 2006 Order). As a result of the Supreme Court's denial of certiorari, the MMS notified Anadarko on February 25, 2010, that the 2008 and 2009 orders had been withdrawn.

Guarantees and Indemnifications Under the terms of the MSA entered into between Kerr-McGee and Tronox, Kerr-McGee agreed to reimburse Tronox for 50% of certain qualifying environmental-remediation costs incurred and paid by Tronox and its subsidiaries before November 28, 2012, subject to certain limitations and conditions. The reimbursement obligation under the MSA was limited to a maximum aggregate reimbursement of $100 million. During 2010, the Company reversed to non-operating income a $95 million liability recorded for this reimbursement obligation as a result of a court-authorized rejection of the MSA. See *Litigation* section of this Note 15.

The Company also 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 connection with the 2006 sale of its Canadian subsidiary, the Company indemnified the purchaser for audit adjustments that may be imposed by the Canadian taxing authorities for periods prior to the sale. At December 31, 2010, other long-term liabilities include a $54 million liability for this contingency. The Company believes it is probable that the remaining indemnification will be settled with the purchaser in cash.

Other The Company is subject to other legal proceedings, claims and liabilities which arise in the ordinary course of its business. In the opinion of Anadarko, the liability (if any) with respect to these claims will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state and local laws and regulations. At December 31, 2010 and 2009, the Company's Consolidated Balance Sheets include liabilities of $96 million for remediation and reclamation obligations. The Company continually monitors the remediation and reclamation process and adjusts its liability for these obligations as necessary.

16. Other Taxes

Taxes incurred, other than income taxes, are as follows:

	Years Ended December 31,		
millions	**2010**	2009	2008
Production and severance	**$ 770**	$ 523	$ 1,135
Ad valorem	**219**	189	221
Other	**79**	34	96
Total	**$ 1,068**	$ 746	$ 1,452

In July 2006, the Algerian parliament approved legislation establishing an exceptional profits tax on foreign companies' Algerian oil production. In December 2006, implementing regulations regarding this legislation were issued. These regulations provide for an exceptional profits tax imposed on gross production at rates of taxation ranging from 5% to 50% based on average daily production volumes for each calendar month in which the price of Brent crude averages over $30 per barrel, retroactively effective to August-2006 production. Exceptional profits tax applies to the full value of production rather than to the amounts in excess of $30 per barrel. On this measurement basis, the Company recognized production tax expense of $508 million, $379 million and $648 million for 2010, 2009 and 2008, respectively.

In response to the Algerian government's imposition of the exceptional profits tax, the Company has notified Sonatrach of its disagreement with the collection of the exceptional profits tax. The Company believes that the Production Sharing Agreement (PSA) provides fiscal stability through several provisions that require Sonatrach to pay all taxes and royalties. To facilitate discussions between the parties in an effort to resolve the dispute, in October 2007, the Company initiated a conciliation proceeding on the exceptional profits tax as provided in the PSA. Any recommendation issued by a conciliation board (Conciliation Board) arising out of the conciliation proceeding is non-binding on the parties. The Conciliation Board issued its non-binding recommendation in November 2008. In February 2009, the Company initiated arbitration against Sonatrach with regard to the exceptional profits tax. In conformance with the terms of the PSA, a notice of arbitration was submitted to Sonatrach. The arbitration hearing on the merits of the claims presented by Anadarko is scheduled for June 2011.

17. Income Taxes

Components of income tax expense (benefit) are as follows:

	Years Ended December 31,		
millions	**2010**	2009	2008
Current			
Federal	**$ 305**	$ (233)	$ 1,111
State	**18**	(13)	40
Foreign	**628**	409	1,031
Total	**951**	163	2,182
Deferred			
Federal	**(72)**	(25)	89
State	**(11)**	(91)	(7)
Foreign	**(48)**	(52)	(116)
Total	**(131)**	(168)	(34)
Total income tax expense (benefit)	**$ 820**	$ (5)	$ 2,148

17. Income Taxes (Continued)

Total income taxes differed from the amounts computed by applying the statutory income tax rate to income (loss) from continuing operations before income taxes. The sources of these differences are as follows:

	Years Ended December 31,		
millions except percentages	**2010**	2009	2008
Income (loss) from continuing operations before income taxes			
Domestic	**$ 855**	$ (660)	$ 3,297
Foreign	**786**	552	2,071
Total	**$ 1,641**	$ (108)	$ 5,368
Statutory tax rate	**35%**	35%	35%
Tax computed at statutory rate	**$ 574**	$ (38)	$ 1,879
Adjustments resulting from:			
State income taxes (net of federal income tax benefit)	**5**	(68)	23
Foreign tax rate differential and valuation allowance	**115**	46	(56)
Non-deductible Algerian exceptional profits tax [1]	**193**	144	246
U.S. tax on foreign income inclusions and distributions	**22**	119	120
Excess U.S. foreign tax credit generated	**—**	(8)	—
U.S. tax impact from losses and restructuring of foreign operations	**(48)**	(94)	(36)
Net changes in uncertain tax positions	**28**	(110)	45
Federal manufacturing deduction	**(23)**	19	(71)
Other—net	**(46)**	(15)	(2)
Total income tax expense (benefit)	**$ 820**	$ (5)	$ 2,148
Effective tax rate	**50%**	5%	40%

(1) Exceptional profits tax is not deductible for Algerian income tax purposes.

Certain tax effects have been recorded directly to the balance sheet at December 31, 2010 and 2009. Tax effects related to internal restructuring of certain foreign operations in prior years have been recorded to other long-term liabilities and are being recognized in the income statement over the estimated life of the related properties. During 2008, liabilities of $47 million were recorded to other long-term liabilities. During 2010 and 2009, $41 million and $51 million, respectively, of the liabilities recorded in prior years were reversed to income. At December 31, 2010, the balance in other long-term liabilities related to the restructuring of certain foreign operations was $51 million. This balance will be recognized as a tax benefit in future periods.

Additionally, the Company recorded an increase in tax liabilities of approximately $310 million for 2008 related to certain acquired subsidiaries for years prior to their acquisition by the Company. The increased tax liabilities were due to completion of audits and administrative appeals, filing amended returns, re-evaluation of contingencies, re-establishment of deferred income tax liabilities related to prior acquisitions and changes to the tax basis of acquired assets and liabilities. Accordingly, these liabilities were recorded with an offsetting increase to goodwill.

17. Income Taxes (Continued)

Components of total deferred taxes are as follows:

	December 31,	
millions	**2010**	2009
Federal	**$ (9,365)**	$ (9,347)
State, net of federal	**(297)**	(296)
Foreign	**(88)**	(135)
Total deferred taxes	**$ (9,750)**	$ (9,778)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets (liabilities) are as follows:

	December 31,	
millions	**2010**	2009
Net current deferred tax assets	**$ 78**	$ 134
Net long-term deferred tax assets	**33**	13
Oil and gas exploration and development operations	**(8,577)**	(8,599)
Mineral operations	**(414)**	(411)
Midstream and other depreciable properties	**(1,314)**	(1,286)
Other	**(1,359)**	(853)
Gross long-term deferred tax liabilities	**(11,664)**	(11,149)
Oil and gas exploration and development costs	**253**	79
Net operating loss carryforward	**311**	416
Foreign tax credit carryforward	**11**	76
Other	**1,682**	1,071
Gross long-term deferred tax assets	**2,257**	1,642
Less: valuation allowance on deferred tax assets not expected to be realized	**(454)**	(418)
Net long-term deferred tax assets	**1,803**	1,224
Net long-term deferred tax liabilities	**(9,861)**	(9,925)
Total deferred taxes	**$ (9,750)**	$ (9,778)

Changes to the valuation allowance, due to changes in judgment regarding the future realizability of deferred tax assets, were an increase of $24 million and a decrease of $10 million for 2010 and 2009, respectively. Changes in the balance of valuation allowance on deferred tax assets are as follows:

millions	**2010**	2009	2008
Balance at January 1	**$ (418)**	$ (509)	$ (472)
Additions	**(49)**	(3)	(37)
Reductions	**13**	94	—
Balance at December 31	**$ (454)**	$ (418)	$ (509)

17. Income Taxes (Continued)

Current taxes receivable (payable) are as follows:

		December 31,	
millions	**Balance Sheet Classification**	**2010**	2009
Income taxes receivable	Accounts receivable—other	$ **47**	$ 115
	Other assets	**5**	57
Total income taxes receivable		**52**	172
Income taxes payable	Accrued expense	**(198)**	(20)
Total income taxes receivable/(payable)		$ **(146)**	$ 152

Tax carryforwards at December 31, 2010, which are available for use on future income tax returns, are as follows:

millions	**Domestic**	**Foreign**	**Expiration**
Net operating loss—regular tax	$ —	$ 589	2011 - indefinite
Net operating loss—state	$ 4,330	$ —	2011 - 2029
Foreign tax credits	$ 11	$ —	2019 - 2020
Texas margins tax credit	$ 39	$ —	2026

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

	Assets (Liabilities)		
millions	**2010**	2009	2008
Balance at January 1	$ **(29)**	$ (132)	$ (238)
Increases related to prior-year tax positions	**(13)**	(17)	(32)
Decreases related to prior-year tax positions	**8**	89	38
Increases related to current-year tax positions	—	(6)	—
Decreases related to current-year tax positions	—	8	—
Settlements	**2**	29	88
Lapse of statutes of limitation	—	—	12
Balance at December 31	$ **(32)**	$ (29)	$ (132)

Included in the balance of unrecognized tax benefits at December 31, 2010, presented in the table above are potential benefits of $(19) million that would affect the effective tax rate on income from continuing operations if recognized. Also included in the balance at December 31, 2010, are benefits of $(13) 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 $(20) million to $(30) 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 recognizes interest and penalties related to unrecognized tax benefits in income tax expense. At December 31, 2010 and 2009, the Company had approximately $26 million and $16 million, respectively, of accrued interest related to uncertain tax positions. During 2010 and 2009, the Company recognized $12 million and $(6) million, respectively, in income tax expense (benefit) for interest and penalties.

17. Income Taxes (Continued)

The following is a list of tax years subject to examination by major tax jurisdiction.

	Tax Year
United States	2007-2010
China	2005-2009
Algeria	2007-2009

18. Supplemental Cash Flow Information

The following table presents amounts of cash paid for interest (net of amounts capitalized) and income taxes, as well as amounts related to non-cash investing and financing transactions.

millions	Years Ended December 31, 2010	2009	2008
Cash paid:			
Interest	**$ 672**	$ 724	$ 762
Income taxes [(1)]	**$ 308**	$ 194	$ 1,060
Non-cash investing activities:			
Fair value of properties and equipment received in non-cash exchange transactions	**$ 37**	$ 280	$ 108
Non-cash financing activities:			
Capital lease obligation	**$ 226**	$ —	$ —

(1) 2008 includes $378 million and $567 million related to taxable gains on divestitures and federal income tax refunds, respectively.

19. Segment Information

Anadarko's primary business segments are vertically integrated within the oil and gas industry. These segments are separately managed due to distinct operational differences and unique technology, distribution and marketing requirements. The Company's three reportable operating 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. The midstream segment engages in gathering, processing, treating and transporting Anadarko and third-party oil, natural gas and NGLs production. The marketing segment sells most of Anadarko's production, as well as third-party purchased volumes.

19. Segment Information (Continued)

To assess the operating results of Anadarko's segments, the chief operating decision maker analyzes income (loss) from continuing operations before income taxes, interest expense, exploration expense, DD&A, impairments and unrealized (gains) losses on derivative instruments, net, less net income attributable to noncontrolling interests (Adjusted EBITDAX). The Company's definition of Adjusted EBITDAX excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Anadarko's definition of Adjusted EBITDAX also excludes exploration expense, as exploration expense 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. Finally, unrealized (gains) losses on derivative instruments, net are excluded from Adjusted EBITDAX because unrealized (gains) losses are not considered to be a measure of asset-operating performance. 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 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) from continuing operations before income taxes.

	Years Ended December 31,		
millions	**2010**	2009	2008
Income (loss) from continuing operations before income taxes	**$ 1,641**	$ (108)	$ 5,368
Exploration expense	**974**	1,107	1,369
DD&A	**3,714**	3,532	3,194
Impairments	**216**	115	223
Interest expense	**855**	702	732
Unrealized (gains) losses on derivative instruments, net [1]	**(114)**	717	(922)
Less: Net income attributable to noncontrolling interests	**60**	32	23
Consolidated Adjusted EBITDAX	**$ 7,226**	$ 6,033	$ 9,941

(1) In the fourth quarter of 2010, the Company revised the definition of Adjusted EBITDAX to exclude the impact of unrealized (gains) losses on derivative instruments, net. All prior periods have been adjusted to reflect this change.

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 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.

19. Segment Information (Continued)

The following table presents selected financial information for Anadarko's operating segments for the respective years ended December 31. Information presented below as "Other and Intersegment Eliminations" includes results from hard minerals non-operated joint ventures and royalty arrangements, operating activities that are not considered operating segments, as well as corporate, financing and certain hedging activities.

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2010					
Sales revenues	$ 5,610	$ 192	$ 5,040	$ —	$ 10,842
Intersegment revenues	4,136	831	(4,572)	(395)	—
Gains (losses) on divestitures and other, net	—	—	—	142	142
Total revenues and other	9,746	1,023	468	(253)	10,984
Operating costs and expenses [(1)]	3,057	576	457	221	4,311
Realized (gains) losses on derivatives, net	—	—	—	(498)	(498)
Other (income) expense, net	—	—	—	(119)	(119)
Net income attributable to noncontrolling interests	—	60	—	—	60
Total expenses and other	3,057	636	457	(396)	3,754
Unrealized (gains) losses on derivatives, net included in marketing revenue	—	—	(4)	—	(4)
Adjusted EBITDAX	$ 6,689	$ 387	$ 7	$ 143	$ 7,226
Net properties and equipment	$ 32,850	$ 3,303	$ 9	$ 1,795	$ 37,957
Capital expenditures	$ 4,672	$ 384	$ —	$ 113	$ 5,169
Goodwill	$ 5,143	$ 139	$ —	$ —	$ 5,282

19. Segment Information (Continued)

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2009					
Sales revenues	$ 3,844	$ 222	$ 4,144	$ —	$ 8,210
Intersegment revenues	3,479	718	(3,842)	(355)	—
Gains (losses) on divestitures and other, net	43	1	—	89	133
Reversal of accrual for DWRRA dispute	657	—	—	—	657
Total revenues and other	8,023	941	302	(266)	9,000
Operating costs and expenses (1)	2,560	585	451	273	3,869
Realized (gains) losses on derivatives, net	—	—	—	(852)	(852)
Other (income) expense, net	—	—	—	(43)	(43)
Net income attributable to noncontrolling interests	—	32	—	—	32
Total expenses and other	2,560	617	451	(622)	3,006
Unrealized (gains) losses on derivatives, net included in marketing revenue	—	—	39	—	39
Adjusted EBITDAX	$ 5,463	$ 324	$ (110)	$ 356	$ 6,033
Net properties and equipment	$ 32,338	$ 3,091	$ 9	$ 1,766	$ 37,204
Capital expenditures	$ 4,001	$ 303	$ —	$ 254	$ 4,558
Goodwill	$ 5,143	$ 139	$ —	$ —	$ 5,282
2008					
Sales revenues	$ 5,760	$ 267	$ 8,052	$ —	$ 14,079
Intersegment revenues	6,933	1,088	(7,532)	(489)	—
Gains (losses) on divestitures and other, net	992	1	—	90	1,083
Total revenues and other	13,685	1,356	520	(399)	15,162
Operating costs and expenses (1)	3,353	905	457	60	4,775
Realized (gains) losses on derivatives, net	—	—	—	339	339
Other (income) expense, net	—	—	—	55	55
Net income attributable to noncontrolling interests	—	23	—	—	23
Total expenses and other	3,353	928	457	454	5,192
Unrealized (gains) losses on derivatives, net included in marketing revenue	—	—	(29)	—	(29)
Adjusted EBITDAX	$ 10,332	$ 428	$ 34	$ (853)	$ 9,941
Net properties and equipment	$ 32,436	$ 2,987	$ 27	$ 1,597	$ 37,047
Capital expenditures	$ 4,274	$ 513	$ —	$ 94	$ 4,881
Goodwill	$ 5,143	$ 139	$ —	$ —	$ 5,282

(1) Operating costs and expenses exclude exploration expense, DD&A and impairments since these expenses are excluded from Adjusted EBITDAX.

19. Segment Information (Continued)

The following table shows Anadarko's sales revenues (based on the origin of the sales) and net properties and equipment by geographic area.

	Years Ended December 31,		
millions	**2010**	2009	2008
Sales Revenues			
United States	**$ 8,806**	$ 6,773	$ 11,503
Algeria	**1,582**	1,133	2,082
Other International	**454**	304	494
Total	**$ 10,842**	$ 8,210	$ 14,079

	December 31,	
millions	**2010**	2009
Net Properties and Equipment		
United States	**$ 34,100**	$ 34,385
Algeria	**1,165**	813
Other International	**2,692**	2,006
Total	**$ 37,957**	$ 37,204

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

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

In 2010, the Company made contributions of $91 million to its funded pension plans, $11 million to its unfunded pension plans and $17 million to its unfunded other postretirement benefit plans. Although reported benefit obligations exceed the fair value of pension and other postretirement plan assets at December 31, 2010, the Company monitors the funded status of its funded pension and other postretirement benefit plans to ensure that plan funds are sufficient to continue paying benefits. Contributions to funded plans increase plan assets while contributions to unfunded plans are used to fund current benefit payments. The Company expects to contribute up to $234 million to its funded pension plans in 2011. In addition, the Company expects to contribute $29 million to its unfunded pension plans and $18 million to its unfunded other postretirement benefit plans in 2011.

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

The following table 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, 2010 and 2009, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2010 and 2009.

	Pension Benefits		Other Benefits	
millions	**2010**	2009	**2010**	2009
Change in benefit obligations				
Benefit obligations at beginning of year	**$ 1,630**	$ 1,280	**$ 316**	$ 319
Service cost	**69**	54	**9**	9
Interest cost	**84**	79	**16**	17
Plan amendments	**6**	—	**—**	3
Actuarial (gain) loss	**217**	313	**(8)**	(16)
Participant contributions	**1**	1	**4**	4
Settlements	**—**	(17)	**—**	—
Benefit payments	**(122)**	(87)	**(21)**	(20)
Foreign-currency exchange-rate changes	**(3)**	7	**—**	—
Benefit obligations at end of year	**$ 1,882**	$ 1,630	**$ 316**	$ 316
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 979**	$ 748	**$ —**	$ —
Actual return on plan assets	**147**	165	**—**	—
Employer contributions	**102**	163	**17**	16
Participant contributions	**1**	1	**4**	4
Settlements	**—**	(17)	**—**	—
Benefit payments	**(122)**	(87)	**(21)**	(20)
Foreign-currency exchange-rate changes	**(3)**	6	**—**	—
Fair value of plan assets at end of year	**$ 1,104**	$ 979	**$ —**	$ —
Funded status of the plans at end of year	**$ (778)**	$ (651)	**$ (316)**	$ (316)
Total recognized amounts in the balance sheet consist of:				
Other assets	**$ 14**	$ 2	**$ —**	$ —
Accrued expenses	**(29)**	(123)	**(17)**	(18)
Other long-term liabilities—other	**(763)**	(530)	**(299)**	(298)
Total	**$ (778)**	$ (651)	**$ (316)**	$ (316)
Total recognized amounts in accumulated other comprehensive income consist of:				
Prior service cost	**$ 12**	$ 8	**$ 5**	$ 3
Net actuarial (gain) loss	**755**	670	**(34)**	(28)
Total	**$ 767**	$ 678	**$ (29)**	$ (25)

The accumulated benefit obligation for all defined-benefit pension plans was $1.7 billion and $1.5 billion at December 31, 2010 and 2009, respectively. For the Company's defined-benefit pension plans with accumulated benefit obligations in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets were $1.8 billion, $1.6 billion and $1.0 billion, respectively, at December 31, 2010, and $1.6 billion, $1.4 billion and $897 million, respectively, at December 31, 2009.

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

The following table sets forth the Company's pension and other postretirement benefit cost and amounts recognized in other comprehensive income (before tax benefit) for the respective years ended December 31.

	Pension Benefits			Other Benefits		
millions	**2010**	2009	2008	**2010**	2009	2008
Components of net periodic benefit cost						
Service cost	**$ 69**	$ 54	$ 56	**$ 9**	$ 9	$ 14
Interest cost	**84**	79	78	**16**	17	20
Expected return on plan assets	**(80)**	(71)	(80)	**—**	—	—
Amortization of net actuarial loss (gain)	**65**	49	14	**(3)**	(2)	—
Amortization of net prior service cost (credit)	**3**	1	1	**(1)**	(1)	(1)
Settlement loss (gain)	**—**	11	—	**—**	—	—
Net periodic benefit cost	**$ 141**	$ 123	$ 69	**$ 21**	$ 23	$ 33
Amounts recognized in other comprehensive income (expense)						
Net actuarial gain (loss)	**$ (151)**	$ (221)	$ (316)	**$ 8**	$ 16	$ 22
Amortization of net actuarial (gain) loss	**65**	49	14	**(3)**	(2)	—
Amortization of settlement (gain) loss	**—**	11	—	**—**	—	—
Net prior service (cost) credit	**(6)**	—	(6)	**—**	—	—
Amortization of net prior service cost (credit)	**3**	1	1	**(1)**	(1)	(1)
Total amounts recognized in other comprehensive income (expense)	**$ (89)**	$ (160)	$ (307)	**$ 4**	$ 13	$ 21

The estimated portion of net actuarial loss and net prior service cost for the pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2011 is $86 million, of which $85 million represents amortization of net actuarial losses and $1 million represents amortization of net prior service cost.

Following are the weighted-average assumptions used by the Company in determining the pension and other postretirement benefit obligations at December 31, 2010 and 2009.

	Pension Benefits		Other Benefits	
percent	**2010**	2009	**2010**	2009
Discount rate	**4.75%**	5.25%	**5.25%**	5.50 %
Rates of increase in compensation levels	**5.00%**	5.00%	**5.00%**	5.00 %

The discount-rate assumption used by the Company represents an estimate of the interest rate at which the pension and other postretirement obligations could effectively be settled on the measurement date. The Company currently uses a yield-curve analysis to support the discount-rate assumption for the plans. This analysis involves the creation of a hypothetical Aa spot yield curve represented by a series of high-quality, non-callable, marketable bonds, and discounting the estimated cash flows associated with benefits to be provided under each plan using interest rates on the curve that correspond to the expected timing of payment. The present value of future plan benefits determined in this manner is then used to estimate a single plan-specific discount rate that equates such present value with the corresponding future undiscounted cash flows. Application of this method resulted in a weighted-average discount-rate assumption (weighted by the plan-level benefit obligation) at December 31, 2010, of 4.75% for pension plans and 5.25% for other postretirement plans.

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

Following are the weighted-average assumptions used by the Company in determining the net periodic pension and other postretirement benefit cost for 2010, 2009 and 2008.

	Pension Benefits			Other Benefits		
percent	**2010**	2009	2008	**2010**	2009	2008
Discount rate	**5.25%**	6.00%	6.00%	**5.50%**	6.00%	6.00%
Long-term rate of return on plan assets	**7.50%**	7.50%	7.75%	**N/A**	N/A	N/A
Rates of increase in compensation levels	**5.00%**	5.00%	5.00%	**5.00%**	5.00%	5.00%

In measuring the other postretirement benefit obligations at December 31, 2009 and 2010, a 9% and 10% annual rate of increase in the per-capita cost of covered health care benefits was assumed for 2010 and 2011, respectively, decreasing gradually to 5% in 2018 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	$ 2	$ (2)
Effect on other postretirement benefit obligation	$ 21	$ (18)

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 large and small cap, international, domestic fixed income, 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 all 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 material direct investments in Anadarko securities included in plan assets. There may be, however, indirect investments in Anadarko securities through the plans' mutual fund investments. The expected long-term rate of return on plan assets assumption was determined using the year-end 2010 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 return. Other asset class returns are derived from their relationship to the equity and fixed income markets.

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

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

December 31, 2010 *millions except percentages*	**Level 1**	**Level 2**	**Level 3**	**Total**	**Percentage of Total**
Cash and cash equivalents	**$ 18**	**$ 30**	**$ —**	**$ 48**	**4%**
Fixed income:					
Bonds, notes and debentures	**71**	**179**	**—**	**250**	**23**
Mortgage-backed securities	**—**	**33**	**—**	**33**	**3**
U.S. Government securities	**17**	**—**	**—**	**17**	**2**
Equity securities:					
International	**92**	**211**	**—**	**303**	**27**
Large cap	**197**	**28**	**—**	**225**	**20**
Non-large cap	**62**	**28**	**—**	**90**	**8**
Other:					
Real estate	**31**	**—**	**9**	**40**	**4**
Private equity	**—**	**—**	**41**	**41**	**4**
Hedge funds and other alternative strategies (1)	**8**	**—**	**49**	**57**	**5**
Total	**$ 496**	**$ 509**	**$ 99**	**$ 1,104**	**100%**

(1) Amount reported as Level 1 represents the net value of long and short positions in public equity securities of $27 million and $19 million, respectively.

December 31, 2009 *millions except percentages*	**Level 1**	**Level 2**	**Level 3**	**Total**	**Percentage of Total**
Cash and cash equivalents	$ 12	$ 49	$ —	$ 61	6%
Fixed income:					
Bonds, notes and debentures	72	169	—	241	25
Mortgage-backed securities	—	37	—	37	4
U.S. Government securities	20	—	—	20	2
Equity securities:					
International	81	174	—	255	26
Large cap	196	29	—	225	23
Non-large cap	46	21	—	67	7
Other:					
Real estate	24	—	—	24	2
Private equity	—	—	25	25	3
Hedge funds and other alternative strategies (1)	11	—	13	24	2
Total	$ 462	$ 479	$ 38	$ 979	100%

(1) Amount reported as Level 1 represents the net value of long and short positions in public equity securities of $25 million and $14 million, respectively.

20. 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 in the tables above. 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-issuer, and is determined by the issuer 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 table sets forth a summary of 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, 2010	**$ 13**	**$ 25**	**$ —**	**$ 38**
Transfers in or out of Level 3	—	—	—	—
Acquisitions/dispositions, net	**35**	**10**	**9**	**54**
Actual return on plan assets:				
Relating to assets sold during the reporting period	—	**2**	—	**2**
Relating to assets still held at the reporting date	**1**	**4**	—	**5**
Balance at December 31, 2010	**$ 49**	**$ 41**	**$ 9**	**$ 99**
Balance at January 1, 2009	$ —	$ 25	$ —	$ 25
Transfers in or out of Level 3	—	—	—	—
Acquisitions/dispositions, net	13	4	—	17
Actual return on plan assets:				
Relating to assets sold during the reporting period	—	(1)	—	(1)
Relating to assets still held at the reporting date	—	(3)	—	(3)
Balance at December 31, 2009	$ 13	$ 25	$ —	$ 38

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 reasonably 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.

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

Expected Benefit Payments

The following table provides an estimate of benefit payments for the next ten years. These estimates reflect benefit increases due to continuing employee service.

millions	Pension Benefit Payments	Other Benefit Payments
2011	$ 201	$ 18
2012	204	19
2013	203	20
2014	201	21
2015	198	22
2016-2020	881	116

Defined-Contribution Plans The Company maintains several defined-contribution benefit plans, including the Anadarko Employee Savings Plan (ESP). All U.S. payroll-based 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 $40 million, $43 million and $37 million for 2010, 2009 and 2008, respectively, related to these plans.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following table shows summary quarterly financial data for 2010 and 2009.

millions except per-share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2010				
Sales revenues	**$ 3,130**	**$ 2,563**	**$ 2,516**	**$ 2,633**
Gains (losses) on divestitures and other, net	**9**	**41**	**34**	**58**
Operating income (loss)	**919**	**377**	**196**	**277**
Net income (loss)	**728**	**(28)**	**(8)**	**129**
Net income attributable to noncontrolling interests	**12**	**12**	**18**	**18**
Net income (loss) attributable to common stockholders	**716**	**(40)**	**(26)**	**111**
Earnings per share:				
Net income (loss) attributable to common stockholders—basic	**$ 1.44**	**$ (0.08)**	**$ (0.05)**	**$ 0.22**
Net income (loss) attributable to common stockholders—diluted	**$ 1.43**	**$ (0.08)**	**$ (0.05)**	**$ 0.22**
Average number common shares outstanding—basic	**493**	**495**	**496**	**496**
Average number common shares outstanding—diluted	**496**	**495**	**496**	**498**
2009				
Sales revenues	$ 1,751	$ 1,894	$ 2,167	$ 2,398
Gains (losses) on divestitures and other, net	45	19	50	19
Reversal of accrual for DWRRA dispute	—	—	657	—
Operating income (loss)	(271)	(322)	779	191
Net income (loss)	(331)	(216)	206	238
Net income attributable to noncontrolling interests	7	10	6	9
Net income (loss) attributable to common stockholders	(338)	(226)	200	229
Earnings per share:				
Net income (loss) attributable to common stockholders—basic	$ (0.73)	$ (0.48)	$ 0.40	$ 0.46
Net income (loss) attributable to common stockholders—diluted	$ (0.73)	$ (0.48)	$ 0.40	$ 0.46
Average number common shares outstanding—basic	460	477	491	492
Average number common shares outstanding—diluted	460	477	493	494

In December 2009, Anadarko adopted revised oil and gas reserve estimation and disclosure requirements that conformed the definition of proved reserves to the Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting rules, issued by the SEC in 2008. An accounting standards update revised the definition of proved oil and gas reserves to require that the average, first-day-of-the-month price during the 12-month period before the end of the year rather than the year-end price, must be used when estimating whether reserve quantities are economic to produce. This same 12-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The rules also allow for the use of reliable technologies to estimate proved oil, natural-gas and natural-gas liquids (NGLs) reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes.

The unaudited supplemental information on oil and gas exploration and production activities for 2010 and 2009 has been presented in accordance with the revised reserve estimation and disclosure rules, which were not applied retrospectively. The 2007 and 2008 data is presented in accordance with Financial Accounting Standards Board (FASB) oil and gas disclosure requirements effective during those periods. However, historical information has been reclassified to conform to the geographic areas required to be disclosed under the revised accounting standard. Disclosures by geographic area include the United States and International. The International geographic area consists of proved reserves located in Algeria, China and Ghana.

The effect of applying the new definition of reliable technology and other non-price related aspects of the updated rules did not significantly impact 2009 net proved reserve volumes, nor does it have a significant impact on 2010 net proved reserve volumes. Approximately 1% and 3% of the Company's total proved reserves, as of year-end 2009 and 2010, respectively, are supported by the use of reliable technologies.

Oil and Gas Reserves

The reserve disclosures that follow reflect estimates of proved reserves, proved developed reserves and proved undeveloped reserves, net of third-party royalty interests, of natural gas, crude oil and condensate, and NGLs owned at each year end and changes in proved reserves during each of the last three years. Natural-gas volumes are in billions of cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch and volumes for oil, condensate and NGLs are in millions of barrels (MMBbls). Total volumes are presented in millions of barrels of oil equivalent (MMBOE). For this computation, one barrel is assumed to be the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserve volumes.

Oil and Gas Reserves (Continued)

Reserves for international locations are calculated in accordance with the terms of their respective 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. 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.

During 2010, Anadarko added 83 MMBOE of proved reserves primarily as the result of successful drilling in the United States. Reserve revisions for 2010 include an increase of 246 MMBOE primarily related to successful infill drilling in the large onshore natural-gas plays, such as the Greater Natural Buttes, Wattenberg and Pinedale fields (where the reserve bookings for the infill wells are treated as a positive revision), and an increase of 29 MMBOE driven by higher oil and gas prices. Sales of proved reserves in place were 6 MMBOE, related to onshore domestic and international assets. Acquisitions of proved reserves in place were 1 MMBOE, related to onshore domestic assets.

In 2009, Anadarko added 70 MMBOE of proved reserves primarily as the result of successful drilling in the United States and international locations. Reserve revisions for 2009 included an increase of 212 MMBOE primarily related to large onshore natural-gas plays, such as the Greater Natural Buttes and Pinedale fields, as a result of successful infill drilling. The revisions include a decrease of 39 MMBOE driven by lower natural-gas prices. Sales and acquisitions of proved reserves in place were 24 MMBOE and 32 MMBOE, respectively, related to onshore domestic assets.

In 2008, Anadarko added 96 MMBOE of proved reserves primarily as a result of successful drilling of development and appraisal wells in the United States. Reserve revisions for 2008 included an increase of 194 MMBOE primarily as a result of successful infill drilling related to the large onshore natural-gas plays, such as the Greater Natural Buttes, Wattenberg and Pinedale fields, in addition to positive revisions to the Peregrino heavy-oil field offshore Brazil, which was sold in 2008, partially offset by a decrease of 102 MMBOE related to price impacts for oil and NGLs. Sales of proved reserves in place for 2008 totaled 137 MMBOE, related to properties located in the United States and Brazil.

Oil and Gas Reserves (Continued)

	Natural Gas (Bcf)			Oil and Condensate (MMBbls)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2007	8,504	—	8,504	521	322	843
Revisions of prior estimates	199	—	199	(17)	17	—
Extensions, discoveries and other additions	336	—	336	36	—	36
Sales in place	(184)	—	(184)	(13)	(91)	(104)
Production	(750)	—	(750)	(40)	(26)	(66)
December 31, 2008	8,105	—	8,105	487	222	709
Revisions of prior estimates	228	—	228	45	16	61
Extensions, discoveries and other additions	210	—	210	13	20	33
Purchases in place	149	—	149	1	—	1
Sales in place	(111)	—	(111)	(2)	—	(2)
Production	(817)	—	(817)	(44)	(25)	(69)
December 31, 2009	**7,764**	**—**	**7,764**	**500**	**233**	**733**
Revisions of prior estimates	**851**	**—**	**851**	**32**	**44**	**76**
Extensions, discoveries and other additions	**363**	**—**	**363**	**13**	**—**	**13**
Purchases in place	**7**	**—**	**7**	**—**	**—**	**—**
Sales in place	**(39)**	**—**	**(39)**	**—**	**—**	**—**
Production	**(829)**	**—**	**(829)**	**(47)**	**(26)**	**(73)**
December 31, 2010	**8,117**	**—**	**8,117**	**498**	**251**	**749**
Proved Developed Reserves						
December 31, 2007	6,308	—	6,308	267	182	449
December 31, 2008	6,117	—	6,117	285	145	430
December 31, 2009	5,884	—	5,884	300	144	444
December 31, 2010	**5,982**	**—**	**5,982**	**303**	**150**	**453**
Proved Undeveloped Reserves						
December 31, 2007	2,196	—	2,196	254	140	394
December 31, 2008	1,988	—	1,988	202	77	279
December 31, 2009	1,880	—	1,880	200	89	289
December 31, 2010	**2,135**	**—**	**2,135**	**195**	**101**	**296**

Oil and Gas Reserves (Continued)

	NGLs (MMBbls)			Total (MMBOE)		
	United States	**International**	**Total**	**United States**	**International**	**Total**
Proved Reserves						
December 31, 2007	141	30	171	2,079	352	2,431
Revisions of prior estimates [(1)]	76	(18)	58	93	(1)	92
Extensions, discoveries and other additions	4	—	4	96	—	96
Sales in place	(2)	—	(2)	(46)	(91)	(137)
Production	(14)	—	(14)	(179)	(26)	(205)
December 31, 2008	205	12	217	2,043	234	2,277
Revisions of prior estimates [(1)]	69	5	74	152	21	173
Extensions, discoveries and other additions	2	—	2	50	20	70
Purchases in place	6	—	6	32	—	32
Sales in place	(3)	—	(3)	(24)	—	(24)
Production	(19)	—	(19)	(199)	(25)	(224)
December 31, 2009	**260**	**17**	**277**	**2,054**	**250**	**2,304**
Revisions of prior estimates [(1)]	**60**	**(4)**	**56**	**235**	**40**	**275**
Extensions, discoveries and other additions	**10**	—	**10**	**83**	—	**83**
Purchases in place	—	—	—	**1**	—	**1**
Sales in place	—	—	—	**(6)**	—	**(6)**
Production	**(23)**	—	**(23)**	**(209)**	**(26)**	**(235)**
December 31, 2010	**307**	**13**	**320**	**2,158**	**264**	**2,422**
Proved Developed Reserves						
December 31, 2007	125	—	125	1,443	182	1,625
December 31, 2008	150	—	150	1,455	145	1,600
December 31, 2009	199	—	199	1,480	144	1,624
December 31, 2010	**222**	—	**222**	**1,523**	**150**	**1,673**
Proved Undeveloped Reserves						
December 31, 2007	16	30	46	636	170	806
December 31, 2008	55	12	67	588	89	677
December 31, 2009	61	17	78	574	106	680
December 31, 2010	**85**	**13**	**98**	**635**	**114**	**749**

(1) Revisions of prior estimates for 2010, 2009 and 2008 total reserves include 312 MMBOE, 125 MMBOE and 158 MMBOE, respectively, of additions generated by Anadarko's infill drilling programs.

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 segments, and other corporate activities are not included.

millions	United States	International	Total
December 31, 2010			
Capitalized			
Unproved properties	**$ 7,518**	**$ 2,331**	**$ 9,849**
Proved properties	**35,792**	**2,687**	**38,479**
	43,310	**5,018**	**48,328**
Less: Accumulated DD&A	**14,302**	**1,176**	**15,478**
Net capitalized costs	**$ 29,008**	**$ 3,842**	**$ 32,850**
December 31, 2009			
Capitalized			
Unproved properties	$ 8,476	$ 1,029	$ 9,505
Proved properties	32,069	2,753	34,822
	40,545	3,782	44,327
Less: Accumulated DD&A	11,010	979	11,989
Net capitalized costs	$ 29,535	$ 2,803	$ 32,338

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 during the year 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 exploration wells, as well as dry hole costs, leasehold impairments, 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 segments, and other corporate activities are not included.

millions	United States	International	Total
Year Ended December 31, 2010			
Property acquisitions			
Unproved	**$ 428**	**$ 91**	**$ 519**
Proved	**22**	**—**	**22**
Exploration	**693**	**585**	**1,278**
Development	**2,368**	**899**	**3,267**
Total Costs Incurred	**$ 3,511**	**$ 1,575**	**$ 5,086**
Year Ended December 31, 2009			
Property acquisitions			
Unproved	$ 270	$ 9	$ 279
Proved	266	—	266
Exploration	743	486	1,229
Development	2,005	881	2,886
Total Costs Incurred	$ 3,284	$ 1,376	$ 4,660
Year Ended December 31, 2008			
Property acquisitions			
Unproved	$ 391	$ 14	$ 405
Proved	26	—	26
Exploration	622	409	1,031
Development	3,240	290	3,530
Total Costs Incurred	$ 4,279	$ 713	$ 4,992

Results of Operations

Results of operations for producing activities consist of all activities within the oil and gas exploration and production segment. Net revenues from production include only the revenues from the production and sale of natural gas, oil, condensate and NGLs. Gains on property dispositions represent net gains on sales of oil and gas properties. Reversal of accrual for Deepwater Royalty Relief Act (DWRRA) dispute represents the reversal of previously recorded liabilities for royalties due on leases subject to litigation with the Department of Interior as described in *Note 15—Contingencies* in the *Notes to Consolidated Financial Statements*. 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. 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, 2010			
Net revenues from production			
Third-party sales	$ 4,369	$ 1,504	$ 5,873
Sales to consolidated affiliates	3,604	532	4,136
Gains on property dispositions	33	(7)	26
	8,006	2,029	10,035
Production costs			
Oil and gas operating	744	86	830
Oil and gas transportation and other	792	22	814
Production-related general and administrative expenses	274	16	290
Other taxes	456	581	1,037
	2,266	705	2,971
Exploration expenses	677	297	974
Depreciation, depletion and amortization	3,281	204	3,485
Impairments related to oil and gas properties	145	—	145
	1,637	823	2,460
Income tax expense	475	563	1,038
Results of operations	$ 1,162	$ 260	$ 1,422

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, 2009			
Net revenues from production			
Third-party sales	$ 2,957	$ 1,046	$ 4,003
Sales to consolidated affiliates	3,088	391	3,479
Gains on property dispositions	2	41	43
Reversal of accrual for DWRRA dispute	657	—	657
	6,704	1,478	8,182
Production costs			
Oil and gas operating	771	88	859
Oil and gas transportation and other	641	22	663
Production-related general and administrative expenses	294	12	306
Other taxes	304	408	712
	2,010	530	2,540
Exploration expenses	810	297	1,107
Depreciation, depletion and amortization	3,138	181	3,319
Impairments related to oil and gas properties	22	—	22
	724	470	1,194
Income tax expense	279	379	658
Results of operations	$ 445	$ 91	$ 536
Year Ended December 31, 2008			
Net revenues from production			
Third-party sales	$ 4,444	$ 1,620	$ 6,064
Sales to consolidated affiliates	5,977	956	6,933
Gains on property dispositions	137	855	992
	10,558	3,431	13,989
Production costs			
Oil and gas operating	936	100	1,036
Oil and gas transportation and other	596	24	620
Production-related general and administrative expenses	256	26	282
Other taxes	685	737	1,422
	2,473	887	3,360
Exploration expenses	1,011	358	1,369
Depreciation, depletion and amortization	2,818	175	2,993
Impairments related to oil and gas properties	113	—	113
	4,143	2,011	6,154
Income tax expense	1,430	912	2,342
Results of operations	$ 2,713	$ 1,099	$ 3,812

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 2010 and 2009 are computed using the average first-day-of-the-month price during the 12-month period for the respective year and using year-end prices for 2008. Prices used for all periods are adjusted only for fixed and determinable amounts under provisions in existing contracts. Estimated future net cash flows for all periods presented are reduced by estimated future development, production, 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-percent discount factor is prescribed by United States Generally Accepted Accounting Principles.

The present value of future net cash flows does not purport to be 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 reserve volumes or commodity prices could have a material effect on the Company's Consolidated Financial Statements.

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

millions	United States	International	Total
December 31, 2010			
Future cash inflows	**$ 82,793**	**$ 20,633**	**$ 103,426**
Future production costs	**26,245**	**6,989**	**33,234**
Future development costs	**8,041**	**1,040**	**9,081**
Future income tax expenses	**16,512**	**5,543**	**22,055**
Future net cash flows	**31,995**	**7,061**	**39,056**
10% annual discount for estimated timing of cash flows	**15,008**	**2,550**	**17,558**
Standardized measure of discounted future net cash flows	**$ 16,987**	**$ 4,511**	**$ 21,498**
December 31, 2009			
Future cash inflows	$ 60,555	$ 14,699	$ 75,254
Future production costs	21,312	5,665	26,977
Future development costs	7,243	1,644	8,887
Future income tax expenses	10,537	3,641	14,178
Future net cash flows	21,463	3,749	25,212
10% annual discount for estimated timing of cash flows	9,938	1,721	11,659
Standardized measure of discounted future net cash flows	$ 11,525	$ 2,028	$ 13,553
December 31, 2008			
Future cash inflows	$ 61,086	$ 7,529	$ 68,615
Future production costs	20,925	4,265	25,190
Future development costs	9,290	1,112	10,402
Future income tax expenses	10,037	939	10,976
Future net cash flows	20,834	1,213	22,047
10% annual discount for estimated timing of cash flows	9,431	645	10,076
Standardized measure of discounted future net cash flows	$ 11,403	$ 568	$ 11,971

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

millions	United States	International	Total
2010			
Balance at January 1	**$ 11,525**	**$ 2,028**	**$ 13,553**
Sales and transfers of oil and gas produced, net of production costs	**(5,707)**	**(1,331)**	**(7,038)**
Net changes in prices and production costs	**6,645**	**2,704**	**9,349**
Changes in estimated future development costs	**(516)**	**(185)**	**(701)**
Extensions, discoveries, additions and improved recovery, less related costs	**1,150**	**—**	**1,150**
Development costs incurred during the period	**424**	**811**	**1,235**
Revisions of previous quantity estimates	**4,181**	**1,235**	**5,416**
Purchases of minerals in place	**8**	**—**	**8**
Sales of minerals in place	**(61)**	**(5)**	**(66)**
Accretion of discount	**1,673**	**421**	**2,094**
Net change in income taxes	**(3,001)**	**(1,305)**	**(4,306)**
Other	**666**	**138**	**804**
Balance at December 31	**$ 16,987**	**$ 4,511**	**$ 21,498**
2009			
Balance at January 1	$ 11,403	$ 568	$ 11,971
Sales and transfers of oil and gas produced, net of production costs	(4,035)	(907)	(4,942)
Net changes in prices and production costs	(2,064)	2,999	935
Changes in estimated future development costs	1,196	(243)	953
Extensions, discoveries, additions and improved recovery, less related costs	717	264	981
Development costs incurred during the period	720	273	993
Revisions of previous quantity estimates	2,389	(26)	2,363
Purchases of minerals in place	206	—	206
Sales of minerals in place	(70)	—	(70)
Accretion of discount	1,642	171	1,813
Net change in income taxes	(192)	(1,044)	(1,236)
Other	(387)	(27)	(414)
Balance at December 31	$ 11,525	$ 2,028	$ 13,553

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Continued)

millions	United States	International	Total
2008			
Balance at January 1	$ 24,276	$ 4,641	$ 28,917
Sales and transfers of oil and gas produced, net of production costs	(7,948)	(1,689)	(9,637)
Net changes in prices and production costs	(15,973)	(6,935)	(22,908)
Changes in estimated future development costs	(19)	46	27
Extensions, discoveries, additions and improved recovery, less related costs	137	—	137
Development costs incurred during the period	806	149	955
Revisions of previous quantity estimates	2,212	1,238	3,450
Sales of minerals in place	(1,096)	(2,216)	(3,312)
Accretion of discount	3,602	1,008	4,610
Net change in income taxes	6,734	4,293	11,027
Other	(1,328)	33	(1,295)
Balance at December 31	$ 11,403	$ 568	$ 11,971

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, 2010.

MANAGEMENT'S ANNUAL REPORT ON INTERAL 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 controls over financial reporting during the fourth quarter of 2010 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 17, 2011 (to be filed with the Securities and Exchange Commission prior to April 1, 2011), 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 internet 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 internet 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 2010, Compensation and Benefits Committee Report on 2010 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, which is incorporated herein by reference.

See *Securities Authorized for Issuance under Equity Compensation Plans* under Item 5 of this Form 10-K, which is incorporated herein by reference.

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

See *Corporate Governance—Board of Directors* and *Transactions with Related Persons* in the Proxy Statement, each of which is incorporated herein by reference.

Item 14. Principal Accountant 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 81.

(2) Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith or designated by asterisks (**) and are furnished herewith. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description	Original Filed Exhibit	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	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 22, 2009	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 22, 2009	3.4 to Form 8-K filed on May 22, 2009	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.	4.1 to Form 8-K filed on September 19, 2006	1-8968
(ii)	Second Supplemental Indenture dated October 6, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A.	4.1 to Form 8-K filed on October 6, 2006	1-8968
(iii)	Ninth Supplemental Indenture dated October 6, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A.	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	4.1 to Form 8-K filed on March 6, 2009	1-8968
(v)	Form of 7.625% Senior Notes due 2014	4.2 to Form 8-K filed on March 6, 2009	1-8968
(vi)	Form of 8.700% Senior Notes due 2019	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	4.1 to Form 8-K filed on June 12, 2009	1-8968

Exhibit Number	Description	Original Filed Exhibit	File Number
4(viii)	Form of 5.75% Senior Notes due 2014	4.2 to Form 8-K filed on June 12, 2009	1-8968
(ix)	Form of 6.95% Senior Notes due 2019	4.3 to Form 8-K filed on June 12, 2009	1-8968
(x)	Form of 7.95% Senior Notes due 2039	4.4 to Form 8-K filed on June 12, 2009	1-8968
(xi)	Officers' Certificate of Anadarko Petroleum Corporation dated March 9, 2010, establishing the 6.200% Senior Notes due 2040	4.1 to Form 8-K filed on March 16, 2010	1-8968
(xii)	Form of 6.200% Senior Notes due 2040	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	4.1 to Form 8-K filed on August 12, 2010	1-8968
(xiv)	Form of 6.375% Senior Notes due 2017	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	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	10.1 to Form 8-K filed on November 17, 2005	1-8968
† (iii)	Anadarko Petroleum Corporation Amended and Restated 1999 Stock Incentive Plan	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	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	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)	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	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)	10.3 to Form 8-K filed on November 13, 2007	1-8968

Exhibit Number	Description	Original Filed Exhibit	File Number
† 10(ix)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Agreement	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	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	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	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	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	10(b)(ii) to Form 10-Q for quarter ended June 30, 2003, filed on August 11, 2003	1-8968
† (xv)	Letter Agreement regarding Post-Retirement Benefits, dated February 16, 2004—Robert J. Allison, Jr.	10(b)(xxxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004	1-8968
† (xvi)	Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007)	10(xxii) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010	1-8968
† (xvii)	Anadarko Retirement Restoration Plan (As Amended and Restated Effective as of November 7, 2007)	10.2 to Form 8-K filed on November 13, 2007	1-8968
† (xviii)	Anadarko Petroleum Corporation Estate Enhancement Program	10(b)(xxxiv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999	1-8968

Exhibit Number	Description	Original Filed Exhibit	File Number
† 10(xix)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives	10(b)(xxxv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999	1-8968
† (xx)	Estate Enhancement Program Agreements effective November 29, 2000	10(b)(xxxxii) to Form 10-K for year ended December 31, 2000, filed on March 15, 2001	1-8968
† (xxi)	Anadarko Petroleum Corporation Management Life Insurance Plan, restated November 1, 2002	10(b)(xxxii) to Form 10-K for year ended December 31, 2002, filed on March 14, 2003	1-8968
† (xxii)	First Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective June 30, 2003	10(b)(xliii) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004	1-8968
† (xxiii)	Second Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective January 1, 2008	10(xxix) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010	1-8968
† (xxiv)	Anadarko Petroleum Corporation Officer Severance Plan	10(b)(iv) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003	1-8968
† (xxv)	Form of Termination Agreement and Release of All Claims Under Officer Severance Plan	10(b)(v) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003	1-8968
† (xxvi)	Director and Officer Indemnification Agreement	10 to Form 8-K filed on September 3, 2004	1-8968
(xxvii)	$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.	10.1 to Form 8-K filed on September 8, 2010	1-8968

	Exhibit Number	Description	Original Filed Exhibit	File Number
†	10(xxviii)	Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan, effective as of May 20, 2008	10.1 to Form 8-K filed on May 20, 2008	1-8968
†	(xxix)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Stock Option Award Agreement	10.3 to Form 8-K filed on November 13, 2009	1-8968
†	(xxx)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement	10.1 to Form 8-K filed on November 13, 2009	1-8968
†	(xxxi)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Performance Unit Award Agreement	10.2 to Form 8-K filed on November 13, 2009	1-8968
†	(xxxii)	Anadarko Petroleum Corporation 2008 Director Compensation Plan, effective as of May 20, 2008	10.2 to Form 8-K filed on May 27, 2008	1-8968
†	(xxxiii)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan	10.3 to Form 8-K filed on May 27, 2008	1-8968
†	(xxxiv)	Anadarko Petroleum Corporation Benefits Trust Agreement, amended and restated effective as of November 5, 2008	10(lvi) to Form 10-K for year ended December 31, 2008, filed on February 25, 2009	1-8968
†	(xxxv)	Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2010)	10(xlvi) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010	1-8968
†	(xxxvi)	Amended and Restated Employment Agreement between James T. Hackett and Anadarko Petroleum Corporation, dated November 11, 2009	10.4 to Form 8-K filed on November 13, 2009	1-8968
	(xxxvii)	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.	10 to Form 10-Q for quarter ended June 30, 2010, filed on August 3, 2010	1-8968

Exhibit Number	Description	Original Filed Exhibit	File Number
† 10(xxxviii)	Retention Agreement, dated August 2, 2010	10.1 to Form 8-K filed on August 6, 2010	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	2010 Report of Miller and Lents, Ltd.		
** 101 .INS	XBRL Instance Document		
** 101 .SCH	XBRL Schema Document		
** 101 .CAL	XBRL Calculation Linkbase Document		
** 101 .LAB	XBRL Label Linkbase Document		
** 101 .PRE	XBRL Presentation Linkbase Document		
** 101 .DEF	XBRL Definition Linkbase Document		

† Management contracts or compensatory plans or arrangements required to be filed pursuant to Item 15.

The total amount of securities of the registrant authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrants and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to the Securities and Exchange Commission.

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 23, 2011

By: ______________________________

Robert G. Gwin
Senior 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 23, 2011.

Name and Signature	**Title**
(i) Principal executive officer:*	
JAMES T. HACKETT James T. Hackett	Chairman and Chief Executive Officer
(ii) Principal financial officer:	
Robert G. Gwin	Senior Vice President, Finance and Chief Financial Officer
(iii) Principal accounting officer:	
M. Cathy Douglas M. Cathy Douglas	Vice President and Chief Accounting Officer
(iv) Directors:*	
ROBERT J. ALLISON, JR. JOHN R. BUTLER, JR. LUKE R. CORBETT H. PAULETT EBERHART PETER J. FLUOR PRESTON M. GEREN III JOHN R. GORDON JAMES T. HACKETT PAULA ROSPUT REYNOLDS	

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

By: ______________________________

Robert G. Gwin, Attorney-in-Fact

EXHIBIT 31(i)

CERTIFICATIONS

I, James T. Hackett, certify that:

1. I have reviewed this annual report on Form 10-K of Anadarko Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 23, 2011

James T. Hackett

James T. Hackett
Chairman and Chief Executive Officer

EXHIBIT 31(ii)

CERTIFICATIONS

I, Robert G. Gwin, certify that:

1. I have reviewed this annual report on Form 10-K of Anadarko Petroleum Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 23, 2011

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

EXHIBIT 32

SECTION 1350 CERTIFICATION OF PERIODIC REPORT

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, James T. Hackett, Chairman and Chief Executive Officer of Anadarko Petroleum Corporation (Company) and Robert G. Gwin, Senior Vice President, Finance and Chief Financial Officer of the Company, certify that:

(1) the Annual Report on Form 10-K of the Company for the period ending December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (Report), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

February 23, 2011

James T. Hackett

James T. Hackett
Chairman and Chief Executive Officer

February 23, 2011

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

This certification is made solely pursuant to 18 U.S.C. Section 1350, and not for any other purpose. A signed original of this written statement required by Section 906 will be retained by Anadarko and furnished to the Securities and Exchange Commission or its staff upon request.

Corporate Information

The common stock of Anadarko Petroleum Corporation is traded on the New York Stock Exchange. Average daily trading volume was 6,833,000 shares in 2010, 6,437,000 shares in 2009 and 7,222,000 shares in 2008. The ticker symbol for Anadarko is APC and daily stock reports published in local newspapers carry trading summaries for the Company under the headings Anadrk or AnadrkPete. The following shows information regarding the market price of and dividends declared and paid on the Company's common stock by quarter for 2010 and 2009.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2010				
Market Price				
High	$ 73.89	$ 75.07	$ 58.42	$ 78.98
Low	$ 60.75	$ 34.54	$ 36.06	$ 55.65
Dividends	$ 0.09	$ 0.09	$ 0.09	$ 0.09
2009				
Market Price				
High	$ 44.00	$ 52.38	$ 66.21	$ 69.37
Low	$ 30.88	$ 37.80	$ 40.28	$ 55.87
Dividends	$ 0.09	$ 0.09	$ 0.09	$ 0.09

Stockholder Services The transfer agent and registrar for Anadarko common stock is BNY Mellon Shareowner Services. Stockholders who need assistance with their accounts or wish to eliminate duplicate mailings should contact:

BNY Mellon Shareowner Services
P.O. Box 358016
Pittsburgh, PA 15252-8016
1.888.470.5786
Website: www.bnymellon.com/shareowner

BNY Mellon Shareowner Services administers the *Buy DIRECT* Direct Purchase and Sale Plan (Buy DIRECT Plan) for Anadarko. The Buy DIRECT Plan provides an opportunity to reinvest dividends and offers an alternative to traditional methods of buying, holding and selling Anadarko common stock. For more information about the Buy DIRECT Plan, please contact BNY Mellon Shareowner Services.

Publications Anadarko will make available to any stockholder, without charge, copies of its Annual Report on Form 10-K as filed with the Securities and Exchange Commission. For copies of this or any Anadarko publication, please contact:

Anadarko Petroleum Corporation
Investor Relations
P.O. Box 1330
Houston, TX 77251-1330
1.832.636.1216 or 1.800.262.9361

Anyone interested in the Company's reports, news releases, presentations and other materials also can find such documents, request copies and sign up for e-mail alerts through our website, www.anadarko.com.

Annual Stockholders' Meeting Anadarko's Annual Meeting of Stockholders will be held Tuesday, May 17, 2011 at The Woodlands Waterway Marriott Hotel and Conference Center, 1601 Lake Robbins Dr., The Woodlands, Texas. Details of the meeting are in the Company's proxy materials.

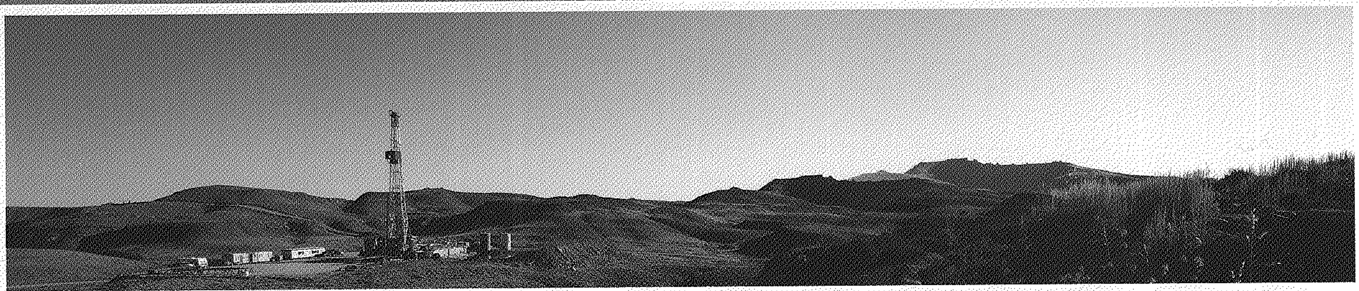
More Information For additional information concerning Anadarko's operations or financial results, please see updated postings on the Company's website at www.anadarko.com, including quarterly operations reports providing extensive project-level detail. Analysts and investors may also contact:

John Colglazier
Vice President, Investor Relations and Communications
1.832.636.2306

Dean Hennings
Manager, Investor Relations
1.832.636.2462

This annual report contains 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. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this annual report, including Anadarko's ability to successfully execute upon its capital program, meet its production and other guidance, identify and execute upon exploration, drilling and development opportunities and complete the projects identified herein. See "Risk Factors" in the Company's 2010 Annual Report on Form 10-K and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

As required by the rules of the New York Stock Exchange (NYSE), in 2010 James T. Hackett, our Chairman and Chief Executive Officer, submitted an annual certification to the NYSE stating that he was not aware of any violation of the NYSE corporate governance listing standards by the company. In addition, we have filed the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 with our 2010 Annual Report on Form 10-K as Exhibits 31(i) and 31(ii).



Board of Directors

As of February 1, 2011

Robert J. Allison, Jr.
Chairman Emeritus
Anadarko Petroleum Corporation

John R. Butler, Jr.
Chairman
J.R. Butler and Company
a reservoir engineering company

Luke R. Corbett
Former Chairman and
Chief Executive Officer
Kerr-McGee Corporation

H. Paulett Eberhart
President and
Chief Executive Officer
CDI Corp.
an engineering and information
technology outsourcing company

Peter J. Fluor
Chairman and
Chief Executive Officer
Texas Crude Energy, Inc.
a private, independent oil and gas
exploration company

Preston M. Geren, III
Senior Adviser and President-Elect
Sid W. Richardson Foundation
a private philanthropic organization

John R. Gordon
Senior Managing Director
Deltec Asset Management LLC
an investment firm

James T. Hackett
Chairman of the Board
and Chief Executive Officer
Anadarko Petroleum Corporation

Paula Rosput Reynolds
Chief Executive Officer
and President
Preferwest, LLC
a business advisory group

Corporate Officers

James T. Hackett
Chairman of the Board
and Chief Executive Officer

R. A. Walker
President and
Chief Operating Officer

Robert P. Daniels
Senior Vice President,
Worldwide Exploration

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

Charles A. Meloy
Senior Vice President,
Worldwide Operations

Robert K. Reeves
Senior Vice President, General
Counsel and Chief Administrative
Officer

Robert D. Abendschein
Vice President,
Corporate Development

Larry J. Abston
Vice President, Corporate Audit

David C. Bretches
Vice President, E&P Services
and Minerals

Bruce W. Busmire
Vice President, Finance and
Treasurer

John M. Colglazier
Vice President, Investor
Relations and Communications

Mario M. Coll, III
Vice President, Chief
Information Officer

M. Cathy Douglas
Vice President and Chief
Accounting Officer

Douglas P. Hazlett
Vice President, Exploration
U.S. Onshore

Darrell E. Hollek
Vice President, Operations
Gulf of Mexico

James J. Kleckner
Vice President, Operations
Rocky Mountains

R. Douglas Lawler
Vice President, Operations
Southern and Appalachia

Ernest A. Leyendecker
Vice President, Corporate
Planning and Gulf of Mexico
Exploration

Donald H. MacLiver
Vice President, Operations
International

A. Scott Moore
Vice President, Marketing

Frank J. Patterson
Vice President, Exploration
International

Gregory M. Pensabene
Vice President,
Government Relations

Danny J. Rea
Vice President, Midstream

Albert L. Richey
Vice President

David L. Siddall
Vice President, Deputy General
Counsel and Corporate Secretary

Donald R. Sinclair
Vice President

Julia A. Struble
Vice President, Human Resources

Cautionary Note to U.S. Investors: Effective January 1, 2010, the United States Securities and Exchange Commission ("SEC") permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms. Anadarko uses certain terms in this document, such as "net risked resource potential" and similar terms that the SEC's guidelines strictly prohibit Anadarko from including in filings with the SEC. U.S. Investors are urged to consider closely the disclosure in Anadarko's Form 10-K for the year ended Dec. 31, 2010, File No. 001-08968, available from Anadarko at www.anadarko.com or by writing Anadarko at: Anadarko Petroleum Corporation, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, Attn: Investor Relations. You can also obtain this report from the SEC by calling 1-800-SEC-0330 or from the SEC's Web site at www.sec.gov.

Anadarko Petroleum Corporation
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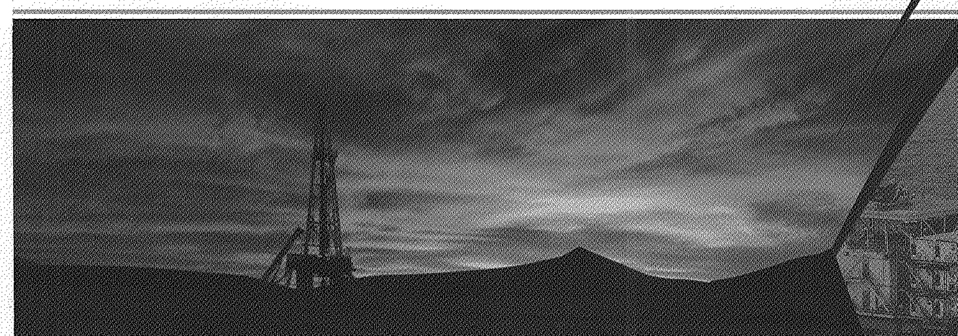
NYSE: APC



Anadarko
Petroleum Corporation