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

FORM 10-K

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

For the Year Ended December 31, 2001
Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION

1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046
(832) 636-1000

Incorporated in the State of Delaware **Employer Identification No. 76-0146568**

Securities registered pursuant to Section 12(b) of the Act:

Common Stock, par value $0.10 per share
Preferred Stock Purchase Rights

The above Securities are listed on the New York Stock Exchange.

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

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 if the disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 ____.

The aggregate market value of the voting stock held by non-affiliates of the registrant on February 28, 2002 was $12,873,673,000.

The number of shares outstanding of the Company's common stock as of February 28, 2002 is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	248,046,910

Part of Form 10-K	Documents Incorporated By Reference
Part III	Portions of the Proxy Statement, dated March 25, 2002, for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held April 25, 2002.

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PART I

Item 1. Business

General

Anadarko Petroleum Corporation is among the largest independent oil and gas exploration and production companies in the world, with 2.3 billion barrels of oil equivalent (BOE) of proved reserves as of December 31, 2001. The Company's major areas of operations are located in the United States, primarily in Texas, Louisiana, the mid-continent region and the western states, Alaska and in the shallow and deep waters of the Gulf of Mexico, as well as in Canada and Algeria. The Company is also active in Venezuela, Qatar, Oman, Egypt, Australia, Tunisia, Congo and Gabon. The Company actively markets natural gas, oil and natural gas liquids (NGLs) production and owns and operates gas gathering systems in its core producing areas. In addition, the Company engages in the hard minerals business through non-operated joint ventures and royalty arrangements in several coal, trona (natural soda ash) and industrial mineral mines located on lands within and adjacent to its Land Grant holdings primarily in Wyoming, Colorado and Utah.

On July 14, 2000, the Company merged with Union Pacific Resources Group Inc., subsequently renamed RME Holding Company (RME). The merger was treated as a tax-free reorganization and accounted for as a purchase business combination. As such, the financial and operating results and property descriptions presented here, unless expressly noted otherwise, are those of Anadarko on a stand-alone basis for the periods up to July 14, 2000 and of the combined Company from that date forward.

The principal subsidiaries of Anadarko are: RME Petroleum Company; RME Holding Company; Anadarko Canada Energy Ltd.; Anadarko Canada Corporation (Anadarko Canada); RME Land Corp.; and, Anadarko Algeria Company, LLC (Anadarko Algeria). Unless the context otherwise requires, the terms *"Anadarko"* or *"Company"* refer to Anadarko and its subsidiaries. The Company's corporate headquarters are located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380, where the telephone number is (832) 636-1000.

Oil and Gas Properties and Activities

Proved Reserves and Future Net Cash Flows

As of December 31, 2001, Anadarko had proved reserves of 1.1 billion barrels of crude oil, condensate and NGLs and 7.0 trillion cubic feet (Tcf) of natural gas. Combined, these proved reserves are equivalent to 2.3 billion barrels of oil or 13.8 Tcf of gas. The Company's reserves have grown significantly over the past three years due to the RME merger in 2000, the acquisitions of Berkley Petroleum Corp. (Berkley) and Gulfstream Resources Canada Limited (Gulfstream) in 2001, substantial natural gas reserves discovered in the Gulf of Mexico, Canada and onshore in the U.S., crude oil reserves discovered in Algeria and Alaska and through other acquisitions of producing properties.

As of December 31, 2001, Anadarko had proved developed reserves of 5.3 Tcf of natural gas and 626 million barrels (MMBbls) of crude oil, condensate and NGLs. Proved developed reserves comprise 65% of the total proved reserves.

The Company's estimates of proved reserves and proved developed reserves at December 31, 2001, 2000 and 1999 and changes in proved reserves during the last three years are contained in the *Supplemental Information on Oil and Gas Exploration and Production Activities — Unaudited (Supplemental Information)* in the Anadarko Petroleum Corporation 2001 Consolidated Financial Statements (Consolidated Financial Statements) under Item 8 of this Form 10-K Annual Report (Form 10-K). The Company files annual estimates of certain proved oil and gas reserves with the U.S. Department of Energy, which are within 5% of the amounts included in the above estimates. See *Critical Accounting Policies* under Item 7 of this Form 10-K.

Also contained in the *Supplemental Information* in the Consolidated Financial Statements are the Company's estimates of future net cash flows, discounted future net cash flows before income taxes and discounted future net cash flows after income taxes from proved reserves.

Sales Volumes and Prices

The following table shows the Company's annual sales volumes. Volumes for natural gas are in billion cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch and volumes for oil, condensate and NGLs are in MMBbls. Total volumes are in million barrels of oil equivalent (MMBOE). For this computation, six thousand cubic feet (Mcf) of gas is the energy equivalent of one barrel of oil, condensate or NGLs.

	2001	2000	1999
United States			
Natural gas (Bcf)	**573**	338	170
Oil and condensate (MMBbls)	**34**	15	9
Natural gas liquids (MMBbls)	**14**	12	7
Total (MMBOE)	**144**	83	44
Canada*			
Natural gas (Bcf)	**121**	46	—
Oil and condensate (MMBbls)	**13**	4	—
Natural gas liquids (MMBbls)	**1**	—	—
Total (MMBOE)	**34**	12	—
Algeria			
Oil and condensate (MMBbls)	**8**	10	6
Total (MMBOE)	**8**	10	6
Other International*			
Natural gas (Bcf)	**1**	1	—
Oil and condensate (MMBbls)	**13**	7	—
Total (MMBOE)	**13**	7	—
Total			
Natural gas (Bcf)	**695**	385	170
Oil and condensate (MMBbls)	**68**	36	15
Natural gas liquids (MMBbls)	**15**	12	7
Total (MMBOE)	**199**	112	50

* In July 2000, Anadarko acquired its production in Canada and other international areas as a result of the merger with RME.

The following table shows the Company's annual average wellhead sales prices and average production costs. The average sales prices include realized gains and losses for derivative contracts the Company enters to manage price risk related to the Company's sales volumes.

	2001	2000	1999
United States			
Sales price			
Natural gas (per Mcf)	**$ 4.15**	$ 4.11	$ 2.08
Oil and condensate (per barrel)	**22.92**	28.72	15.79
Natural gas liquids (per barrel)	**16.39**	21.65	13.40
Production cost (per BOE)	**$ 4.60**	$ 4.91	$ 4.28
Canada*			
Sales price			
Natural gas (per Mcf)	**$ 4.27**	$ 4.38	—
Oil and condensate (per barrel)	**17.33**	27.38	—
Natural gas liquids (per barrel)	**18.32**	—	—
Production cost (per BOE)	**$ 5.53**	$ 6.80	—
Algeria			
Sales price			
Oil and condensate (per barrel)	**$23.97**	$28.76	$18.23
Production cost (per BOE)	**$ 2.33**	$ 2.61	$ 1.84
Other International*			
Sales price			
Natural gas (per Mcf)	**$ 1.22**	$ 1.08	—
Oil and condensate (per barrel)	**14.35**	18.35	—
Production cost (per BOE)	**$ 5.64**	$ 8.24	—
Total			
Sales price			
Natural gas (per Mcf)	**$ 4.16**	$ 4.13	$ 2.08
Oil and condensate (per barrel)	**20.32**	26.49	16.83
Natural gas liquids (per barrel)	**16.51**	21.70	13.40
Production cost (per BOE)	**$ 4.73**	$ 5.16	$ 3.97

* In July 2000, Anadarko acquired its production in Canada and other international areas as a result of the merger with RME.

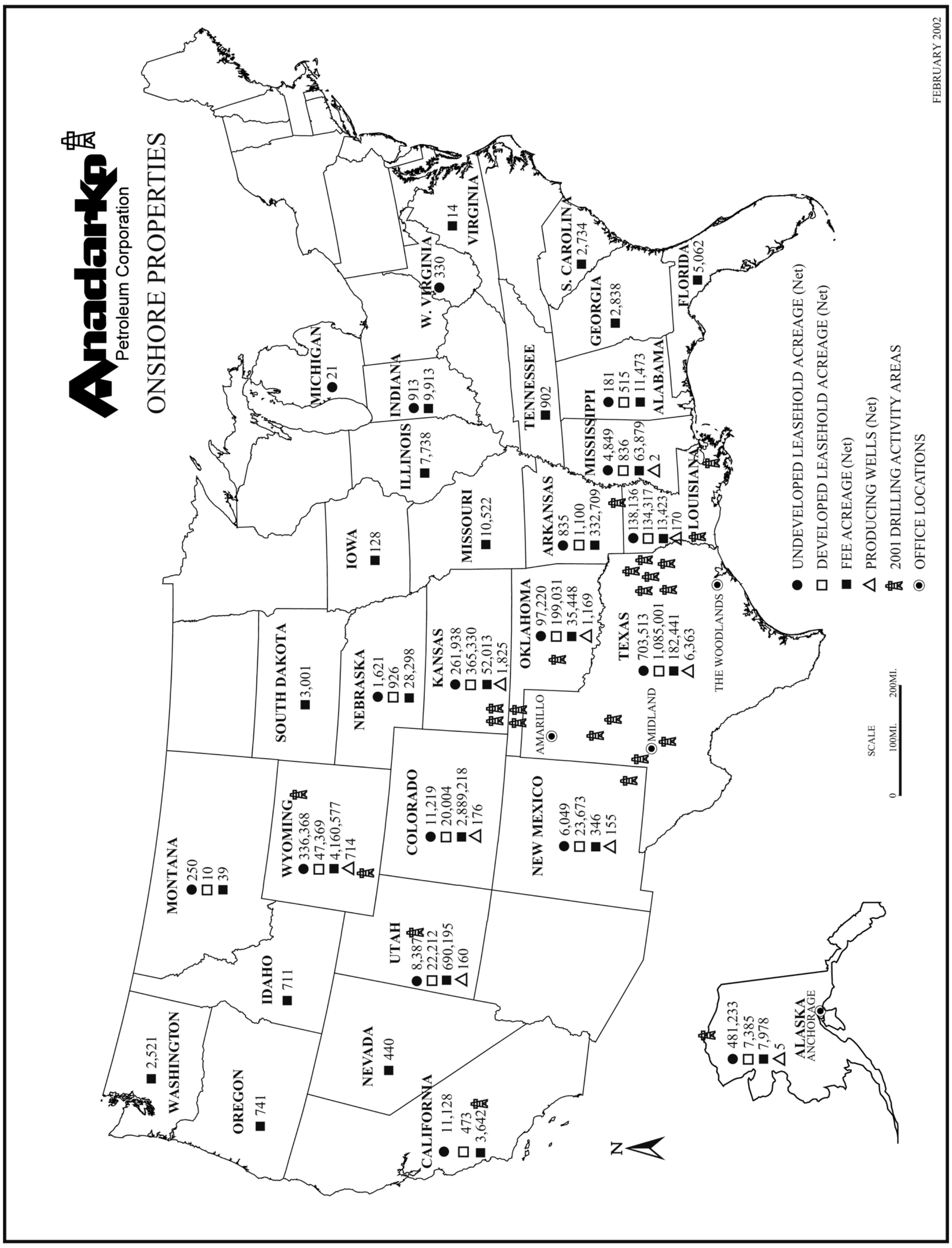
Additional information on volumes, prices and markets is contained in *Financial Results* and *Marketing Strategies* under Item 7 of this Form 10-K. Information on major customers is contained in *Note 10* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Properties and Activities — United States

United States reserves comprised 61% of Anadarko's total proved reserves at year-end 2001 compared to 64% in 2000 and 71% in 1999. The accompanying maps illustrate by state Anadarko's undeveloped and developed lease and fee acreage, number of net producing wells and other data relevant to its domestic onshore and offshore oil and gas operations.

Onshore — Lower 48 States

Overview About 50% of the Company's proved reserves are located onshore in the Lower 48 states, with operations primarily in Texas, Louisiana, the mid-continent region and western states. In 2001, average production from the Company's onshore properties was 1,241 million cubic feet per day (MMcf/d) of gas and 90 thousand barrels per day (MBbls/d) of crude oil, condensate and NGLs, or 55% of the Company's total production volumes. During 2001, Anadarko participated in a total of 855 wells in the Lower 48 states with a success rate of 96%. Drilling results included 673 gas wells, 148 oil wells and 34 dry holes. Anadarko has



Anadarko
Petroleum Corporation
ONSHORE PROPERTIES
WASHINGTON
■ 2,521
OREGON
■ 741
IDAHO
■ 711
MONTANA
● 250
□ 10
■ 39
NEVADA
■ 440
CALIFORNIA
● 11,128
□ 473
■ 3,642
UTAH
● 8,387
□ 22,212
■ 690,195
△ 160
WYOMING
● 336,368
□ 47,369
■ 4,160,577
△ 714
COLORADO
● 11,219
□ 20,004
■ 2,889,218
△ 176
SOUTH DAKOTA
■ 3,001
NEBRASKA
● 1,621
□ 926
■ 28,298
NEW MEXICO
● 6,049
□ 23,673
■ 346
△ 155
KANSAS
● 261,938
□ 365,330
■ 52,013
△ 1,825
OKLAHOMA
● 97,220
□ 199,031
■ 35,448
△ 1,169
AMARILLO
MIDLAND
TEXAS
● 703,513
□ 1,085,001
■ 182,441
△ 6,363
THE WOODLANDS
IOWA
■ 128
MISSOURI
■ 10,522
ARKANSAS
● 835
□ 1,100
■ 332,709
LOUISIANA
● 138,136
□ 134,317
■ 13,423
△ 170
ILLINOIS
■ 7,738
INDIANA
● 913
■ 9,913
MICHIGAN
● 21
TENNESSEE
■ 902
MISSISSIPPI
● 4,849
□ 836
■ 63,879
△ 2
ALABAMA
● 181
□ 515
■ 11,473
GEORGIA
■ 2,838
FLORIDA
■ 5,062
S. CAROLINA
■ 2,734
W. VIRGINIA
● 330
VIRGINIA
■ 14
ALASKA
ANCHORAGE
● 481,233
□ 7,385
■ 7,978
△ 5
N
SCALE
0 100MI. 200MI.
● UNDEVELOPED LEASEHOLD ACREAGE (Net)
□ DEVELOPED LEASEHOLD ACREAGE (Net)
■ FEE ACREAGE (Net)
△ PRODUCING WELLS (Net)
2001 DRILLING ACTIVITY AREAS
◉ OFFICE LOCATIONS
FEBRUARY 2002

2,322,000 gross (1,583,000 net) undeveloped lease acres, 2,714,000 gross (1,901,000 net) developed lease acres and 9,532,000 gross (8,511,000 net) fee acres onshore in the Lower 48 states.

East Texas and Louisiana

Bossier Play-Overview Anadarko has taken a number of steps over the past few years to significantly expand the scope of its Bossier operations and to position the Company to build on an already solid record of success. Since operations began in 1996, the Company has achieved a development success rate of nearly 100% and expanded the play from east Texas into north Louisiana. The Bossier play consists of multiple fields and multiple pay zones, including the Cotton Valley Bossier Sands, Rodessa, Pettet, Travis Peak and Cotton Valley Lime formations. The majority of the Company's production is from the Bossier Sand interval. Bossier production is typical of a "tight" gas reservoir — one with low porosity and permeability. Wells are characterized by steep initial decline rates but have long reserve lives. This means the average well produces gas initially at a rate of about 3 MMcf/d and declines to less than 1 MMcf/d after one year. The producing rate then declines at a much slower rate and the well continues to produce for many years. Some of Anadarko's gas wells in the Bossier play have tested at much higher initial rates than the average rate. These wells initially produce at higher rates, decline rapidly, but recover more gas than the average well.

In 2001, Anadarko continued drilling in the Bossier play at a brisk pace. At the peak of activity in July 2001, the Company had a total of 32 rigs drilling (26 in east Texas and six in north Louisiana). During 2002, the Company expects to operate about 11 rigs in the play (six in east Texas and five in north Louisiana). This decrease in activity reflects the Company's decision in the second half of 2001 to focus on increasing its inventory of drilling prospects by identifying new reserves through increased exploration, rather than growing production during the current down cycle for energy prices.

In 2001, the Company drilled 175 wells, bringing the total Bossier play well count to about 450 wells as of December 31, 2001. Of the wells drilled in 2001, 23 were exploratory wells of which 19 were successful. Bossier volumes for 2001 totaled 94 Bcf (net), or roughly 14% of the Company's total gas production, making it Anadarko's largest onshore gas area. For 2002, the Company is planning to drill 64 wells in the Bossier play. The Bossier exploratory program is expected to be $56 million and total spending in the play is expected to be $170 million. Through its ongoing development and exploration programs, although decreased at the present time, Anadarko continues to extend the limits of the Bossier play.

Bossier-East Texas Anadarko has drilled over 400 Bossier wells in east Texas as of the end of 2001. During the last half of 2001, activity was curtailed as capital was shifted to other areas. Exploration, however, continued at a steady pace to expand the play deeper into the basin and identify new field reserves. As of year-end 2001, two wildcat wells were drilling and another three wells were being completed. Anadarko continued to build its strong acreage position by leasing an additional 88,000 acres throughout the year, giving Anadarko a total of 283,000 net acres at year-end 2001.

Bossier-North Louisiana The Vernon field, acquired by Anadarko in 1999, was producing 45 MMcf/d of gas (net) from 46 wells at the end of 2001 compared to 18 wells producing 5 MMcf/d of gas (net) in 1999.

Anadarko has extended the Vernon field in all directions through successful exploration and development drilling in 2001. A total of 24 wells, seven of which were exploratory, were drilled in 2001, more than doubling production. The Ansley prospect was drilled immediately west of the Vernon field, significantly expanding the area of known reserves. The well logged 125 feet of net pay and subsequently tested 8 MMcf/d of gas in January 2002. The Hodde 28-1 well (100% working interest (WI)) was completed at a rate of 11 MMcf/d of gas. This test confirmed expansion of the field to the southwest.

Seismic, new depositional models and better fracture/stimulation technology have been keys to growth in the Vernon field. Anadarko's position in the play now totals over 99,000 net acres, an increase of 51,000 net acres from 2000. Anadarko plans to drill 16 wells in 2002, which includes five exploration wells.

Carthage Anadarko's four rig infill drilling program in the Carthage area of east Texas continued during 2001. The wells target primarily the tight gas sand formations in the Cotton Valley interval. The application of a new fracture stimulation technique has resulted in significantly better performance and economics from these wells, with initial production rates averaging nearly 3 MMcf/d of gas from recent completions with many wells producing initial rates of over 4 MMcf/d of gas. Prior techniques resulted in average initial rates of

2 MMcf/d of gas. Anadarko began to reduce activity in the Carthage area during the last half of 2001, with a shift in capital to more long-term exploration. For 2001, the multi-rig infill program in Panola, Henderson and Rusk counties of Texas resulted in drilling a total of 34 wells aimed at the Cotton Valley Formation.

In addition to the Cotton Valley interval, Anadarko also completed a number of wells in shallower formations such as the Blossom. Anadarko utilizes a fleet of about four workover rigs to help maintain production levels in the area. The Company plans to drill two wells in the Carthage area in 2002.

South Louisiana During 2001, volumes from the more than 40 Anadarko-operated wells on production in the area averaged 30 MMcf/d of gas and 6 MBbls/d of oil and NGLs (net). The development drilling program in the Kent Bayou field (67% WI) of Terrebonne Parish, Louisiana was a focal point of Anadarko's activities in south Louisiana during 2001. The production facility was also upgraded. In January 2002, two successful recompletions resulted in increasing production to 46 MMcf/d of gas and 10 MBbls/d of condensate (net).

Central Texas The Giddings field in Washington, Fayette, Lee, Brazos, Burleson and Robertson counties of central Texas is the focal point of Anadarko's horizontal drilling program targeting the Georgetown, Buda, Austin Chalk and Glen Rose formations. During 2001, Anadarko continued to exploit these multiple pay zones in central Texas. The Company's land holdings throughout central Texas exceed 745,000 net acres, which are largely held by production. At year-end 2001, Anadarko had five rigs operating throughout its central Texas play: two in the Georgetown; two in the Buda and Austin Chalk; and, one in the Glen Rose formations. During 2001, net volumes from the Company's more than 1,600 producing wells throughout central Texas were nearly 196 MMcf/d of gas and more than 14 MBbls/d of oil. In 2002, the Company expects to drill 41 development wells and five exploration wells as part of a five-rig program. The Company has budgeted approximately $82 million for these projects in 2002.

Buda/Austin Chalk The Company continued its successful redevelopment program of the Buda and Austin Chalk formations in the Giddings field. During 2001, 57 wells were successfully re-entered to horizontally drill these formations. In 2001, production averaged 146 MMcf/d of gas and 14 MBbls/d of oil (net).

The cost to re-enter a well is about half the cost of drilling a new well. The future potential for testing additional zones with horizontal laterals could extend throughout Anadarko's Austin Chalk acreage holdings and 1,350 existing wells operated by the Company.

Georgetown During 2001, Anadarko completed nine wells in the deep Giddings over-pressured area. In 2001, production averaged 45 MMcf/d of gas (net) from ten wells. The Company owns a 100% working interest in nine of the ten wells. A separate intermediate-depth Georgetown play is being evaluated by the Company using re-entries to minimize cost at this stage of exploration.

Glen Rose The new Glen Rose horizontal play continues to be expanded. In 2001, production averaged 5 MMcf/d of gas (net) in the Mossy Grove field of Madison and Walker counties, Texas. The Company drilled three wells (75% WI) in the area during 2001.

East Chalk The Company's development program continued in the East Chalk, which is located in southeast Texas and Louisiana. The Company holds 310,000 net acres in the area. Total net production in the East Chalk during 2001 averaged 22 MMcf/d of gas and 6 MBbls/d of oil, condensate and NGLs. In the Brookeland field of the East Chalk, six wells were completed in 2001.

Permian Basin Anadarko drilled 140 wells, performed 85 successful workovers and recompletions, expanded two major waterfloods and installed one CO_2 flood in the Permian basin during 2001. Net production for 2001 averaged 89 MMcf/d of gas and 13 MBbls/d of oil, which resulted in cumulative net production of 10 MMBOE. This compares to net production in 2000 of 12 MBbls/d of oil and 54 MMcf/d of gas, which resulted in cumulative net production of 8 MMBOE. Anadarko has interests in 389,000 gross (275,000 net) acres in the Permian basin and operates approximately 5,400 wells.

In the Ozona field (65% WI), located in Crockett County, Texas, development continued with the Company drilling and completing 96 wells and recompleting 50 wells during 2001. These operations added 35 MMcf/d of gas production, which resulted in total field gas production of 94 MMcf/d of gas (gross). Anadarko operates 1,900 wells in the Ozona field and plans to drill 30 new wells and recomplete 40 wells in 2002.

Tertiary CO_2 flood operations in the San Andres reservoir of the Slaughter field were implemented during 2001 at the H.T. Boyd lease (100% WI), located in Cochran County, Texas. Although the Company has previously operated CO_2 flood projects, this is the first to be installed by Anadarko.

Waterflood operations in the Clearfork reservoir in the TXL South Unit (67% WI), located in Ector County, Texas, were expanded to cover the central and southern portions of the unit. Water injection, which began in May of 2001, is expected to increase production to 2 MBbls/d of oil (net) by year-end 2002.

A San Angelo/Clearfork waterflood development project continued throughout 2001 in the Snyder field (100% WI) located in Howard County, Texas. Anadarko drilled six production and 12 injection wells during 2001. Anadarko has drilled 137 wells in the Snyder field on 2,300 acres acquired in 1998 and 1999.

Mid-Continent

Hugoton Embayment Anadarko's activities in the Hugoton Embayment, located in southwest Kansas and the Oklahoma and Texas panhandles, are focused on the deeper oil and gas zones below the shallow gas producing formations. Anadarko controls 987,000 gross (913,000 net) acres in this area and operates about 2,700 wells. The deep drilling program in Kansas and the Oklahoma panhandle utilizes 3-D seismic technology to locate oil and gas bearing zones in the Morrow, Chester and St. Louis formations. This multi-pay potential lowers the drilling risk for the area. The average depth for a well in this area is 6,000 feet. Anadarko currently owns or has license to 1,500 square miles of 3-D seismic in the Hugoton Embayment and has drilled 144 successful deep wells based on this data over the past seven years. Successful wells drilled in 2001 include the Carpenter A-4, which had an initial production rate of 13 MMcf/d, and the Brown L-1, which tested at a rate of 800 barrels per day (Bbls/d) of oil and 3 MMcf/d of gas.

The Company's net production from the Hugoton Embayment area during 2001 was 183 MMcf/d of gas and 17 MBbls/d of oil, condensate and NGLs. Total net volumes for 2001 were approximately 18 MMBOE (109 Bcf of gas equivalent). In 2001, the Company drilled 56 wells in the Hugoton Embayment. Anadarko also recompleted 12 wells and carried out workover operations on 152 wells in the area. In 2002, the Company has budgeted $20 million in the area and plans to drill about 23 wells.

Texas Panhandle During 2001, the Company drilled one shallow well in the West Panhandle Red Cave field in the Texas portion of the Hugoton Embayment. Anadarko produced an average of 28 MMcf/d of gas (net) from 211 wells completed in the Brown Dolomite or Red Cave formations in the West Panhandle field. This gas is exceptionally rich in NGLs producing 40 barrels of NGLs per MMcf of gas in the Red Cave wells and 145 barrels of NGLs per MMcf of gas in the Brown Dolomite wells.

Central Oklahoma During 2001, net production from the 291 Golden Trend wells operated by the Company was 20 MMcf/d of gas and 600 Bbls/d of oil. In the last five years, Anadarko has drilled about 100 wells in the Golden Trend, implemented a 40 acre infill drilling program and substantially increased its leasehold position. In 2001, Anadarko drilled and completed 20 wells in the Golden Trend. The play, located in Grady, Garvin and McClain counties of Oklahoma, targets several different formations including deeper Sycamore, Woodford, Hunton, Viola and Bromide. During 2001, rig activity steadily dropped in the area as the Company re-evaluated play economics in light of falling gas prices and high oilfield service costs. The abundant inventory of development drilling locations will be revisited when market factors improve.

The Company's Golden Trend deep gas assets are complemented by the Anadarko-operated Antioch Gathering System. The gathering system consists of 150 miles of pipe connecting over 280 wells and provides increased operational control and market flexibility. During 2001, the Antioch system moved an average of 25 MMcf/d of gas. In the area, Anadarko also operates five enhanced oil recovery units, which produce from shallower horizons. The enhanced oil recovery units are comprised mainly of CO_2 flood projects and produced 3 MBbls/d of oil and 3 MMcf/d of gas in 2001. In 2002, the Company has budgeted $19 million in the central Oklahoma area. The majority of this capital is planned for projects within the enhanced recovery units.

Western States

Overview Anadarko doubled its activity level in the western states area in 2001 and increased operated production by 21%, achieving major goals set following the RME merger in 2000. The western states area primarily includes the Company's oil and gas properties in the Land Grant area of Wyoming, Colorado and Utah. The Land Grant was granted to a predecessor of RME by the federal government in the mid-1800s. Economics on the Land Grant acreage are greatly enhanced by Anadarko's fee mineral ownership position. For example, in a typical outside-operated well on the Land Grant, Anadarko would have a 25% working interest with a 33.75% net revenue interest, whereas for a comparable outside-operated well outside the Land Grant, Anadarko would have a 25% working interest with a 20% net revenue interest. The Company's operations in the Land Grant are concentrated in the Green River basin and the Overthrust area.

The Company currently has approximately 8,751,000 gross (8,186,000 net) acres, principally attributable to its Land Grant ownership. Anadarko and its partners drilled over 300 wells in the area in 2001 compared to 160 wells in 2000, with an overall success rate of 96%. Of the total, 136 wells were Company-operated, about double the 2000 activity. Anadarko's 2001 production from the western states area averaged 287 MMcf/d of gas, 9 MBbls/d of oil and 14 MBbls/d of NGLs.

Anadarko plans to invest about $90 million in the western states area for exploration and development in 2002. The Company's 2002 plans include drilling 212 development and 14 exploratory wells in Wyoming, Colorado and Utah.

Wyoming In the Green River basin of Wyoming, Anadarko-operated rigs focused on conventional drilling projects in the Wamsutter and Brady areas. During 2001, Anadarko operated from one to three rigs and had interests in up to 15 outside-operated rigs. In 2001, the Company drilled or participated in approximately 160 wells in the Green River basin. In 2002, the Company plans to drill 210 additional wells in this area.

Anadarko continued to exploit the Almond and Lewis formations within the greater Wamsutter area, successfully extending production limits both to the east and west. Anadarko participated in 98 Wamsutter area wells during 2001.

Anadarko's exploration efforts gained momentum during 2001. The Company acquired over 415 square miles of 3-D and almost 350 miles of 2-D seismic data for future exploration in the Green River basin, the Overthrust Belt and the Hanna and Laramie basins before shutting down for winter range restrictions.

Utah Coalbed Methane During 2001, the Company drilled 18 wells in the Helper and Drunkard's Wash fields in Utah. At year-end 2001, gross wellhead volumes from Anadarko's coalbed methane wells in Utah were about 52 MMcf/d of gas and are expected to increase by year-end 2002 as de-watering continues.

Wyoming Coalbed Methane The Company's Big George project in the Powder River basin of Wyoming started in late 2001. At year-end, the project was producing 4 MMcf/d of gross wellhead gas, primarily from 20 wells. Gas production is expected to increase as the additional 67 wells drilled in 2001 are brought on-line and de-watered. The majority of construction required to bring the new wells on-line was completed in 2001.

California Anadarko acquired leasehold interests in the San Joaquin Basin with the Berkley acquisition during 2001. Anadarko has interests in 29,000 gross acres in East Lost Hills and has 17,000 gross acres under option in Pyramid Hills. During 2001, Anadarko took over operations on four wells. At year-end 2001, one well was producing, one well tested at 1.5 MMcf/d of gas (gross) and was awaiting production facilities, one well was temporarily abandoned and one well was still drilling. Two additional exploration wells were spud in late 2001 and are still drilling.

Alaska

Overview Anadarko's activity in Alaska is concentrated primarily on the North Slope. The Company also has interests in the Cook Inlet of south central Alaska. During 2001, Anadarko participated in a total of 20 oil wells in Alaska with a success rate of 100%. The Company had interests in 1,400,000 gross (481,000 net) undeveloped lease acres, 32,000 gross (7,000 net) developed lease acres and 16,000 gross (8,000 net) fee acres in Alaska at year-end 2001. In addition, the Company is finalizing agreements on leases covering 1,151,000 gross acres in the Foothills area of the North Slope from Arctic Slope Regional Corporation under an exclusive option-to-lease agreement, under which Anadarko also retains the right to acquire leases on an additional 1,941,000 acres. During 2001, Anadarko added to its significant acreage position by participating in the North Slope/Beaufort Areawide 2001 lease sale. The Company, separately and in partnership with other companies, submitted winning bids on 31 tracts covering 105,000 gross acres. The Company is also waiting for final approval from a 2001 lease sale in the Foothills area for 207,000 gross acres. Combined, this gives the Company exploration access to almost five million gross acres in Alaska.

North Slope In November 2000, production began from the Alpine field (22% WI) on Alaska's North Slope. The Alpine field produced an average of 88 MBbls/d of oil in 2001. In the fourth quarter 2001, Alpine set field production records, producing more than 108 MBbls/d of oil during a single day. With Alpine's higher-than-expected production and new production anticipated from satellite fields, the Alpine production facility will be further expanded to 135 MBbls/d of capacity. The first phase of the expansion should be completed mid-2003. As of year-end 2001, 49 wells — 27 production wells and 22 injection or service wells — have been completed. The entire Alpine development program will have more than 100 horizontal wells from two drill sites. During the fourth quarter of 2001, construction was finished at Colville Delta 2, the drill site used to develop the western part of the field, and oil production from that portion of the field began.

The Alpine field, which represents the nation's largest onshore oil discovery in more than a decade, serves as an excellent example of commitment to minimizing the environmental impact of exploration and production operations in sensitive areas. The production facilities for the field are situated on about 100 acres, roughly one-third of one percent of the subsurface reservoir area being developed. In addition, Alpine is a zero discharge facility; the waste generated is reused, recycled or disposed of properly. There is no permanent road to the field; therefore, ice roads, which leave no trace on the tundra, are utilized during the winter. Equipment, supplies and personnel are transported by small aircraft year-round.

In 2001, Anadarko and its partner announced the Nanuq discovery, a satellite oil field about four miles south of the Alpine field. The Nanuq accumulation is the second satellite field to be discovered near Alpine. The first satellite field, the Fiord, was announced as a discovery in 1999. Both the Nanuq and Fiord satellites (22% WI) will be developed and produced through the expanded Alpine facility beginning in the 2005-2006 time frame, filling in the natural production decline of Alpine.

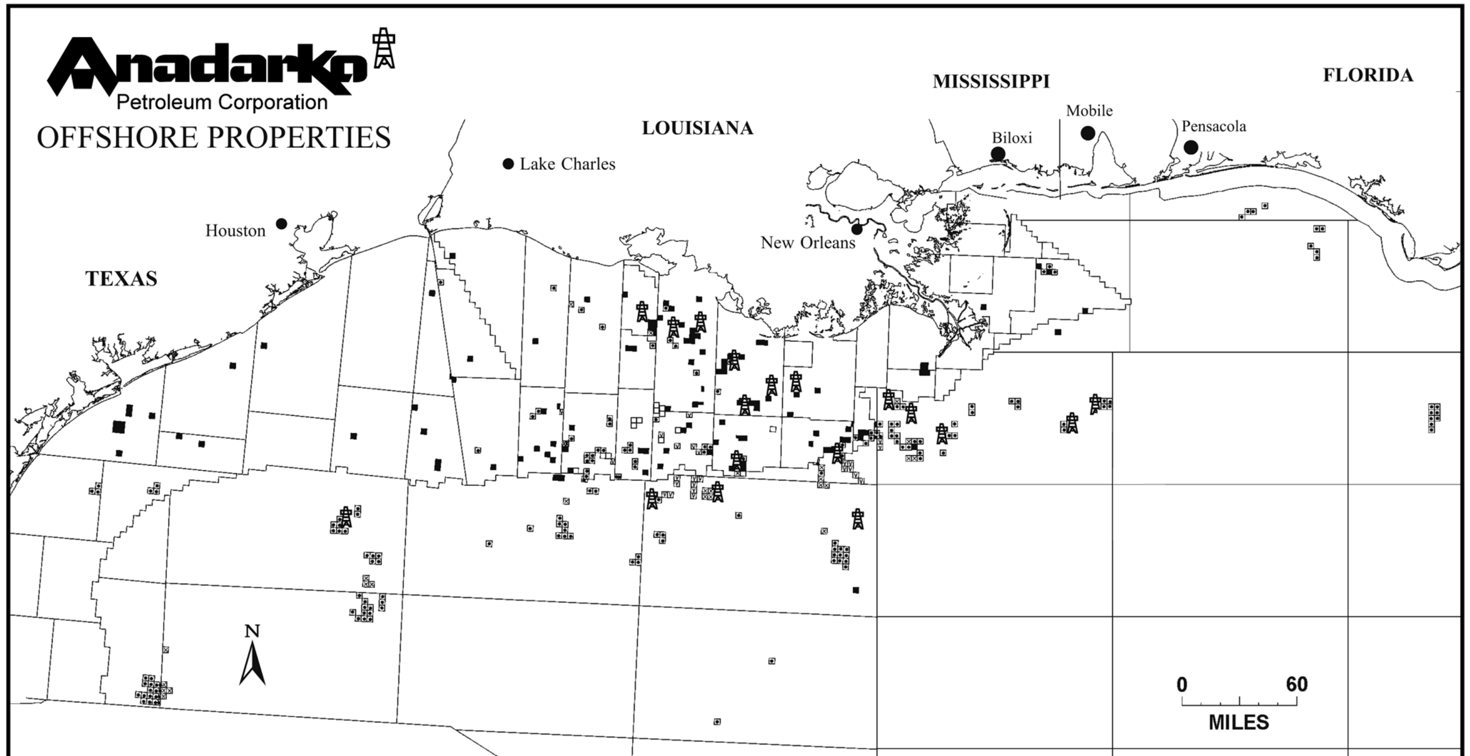
During 2001, Anadarko and its partner announced first discoveries in the National Petroleum Reserve-Alaska (NPR-A). During the past two winter drilling seasons, five wells and one sidetrack well, which targeted the Alpine producing horizon, encountered oil and gas and condensate. These are the Spark #1, Spark #1A, Moose's Tooth C, Lookout #1, Rendezvous A and Rendezvous #2 (22% WI). An additional well, that was drilled in 2000, was a dry hole. These outside-operated discoveries are located from 15 to 25 miles southwest of the Alpine field.

Anadarko expects to drill its first operated wildcat on the North Slope in 2002. The exploration well is the Altamura #1 (100% WI), located in the NPR-A just south of the Moose's Tooth discovery. In addition, the Company plans to participate in the acquisition of 1,300 square miles of 3-D seismic and 600 miles of 2-D seismic and continue the Company-operated Foothills exploration program. The Company also expects to participate in up to seven additional exploration wells with partners, including delineation of last year's discoveries at Moose's Tooth. Warm weather in the 2001-2002 season has delayed access to the North Slope and some drilling may be postponed due to schedule limitations.

Cook Inlet In 1999, Anadarko completed a long-term test to confirm the potential commerciality of its discovery at the Lone Creek No. 1 well (50% WI) on the Moquawkie prospect. In 2001, the Company and its partner began securing the necessary permits and agreements to develop this discovery. Anadarko holds approximately 56,000 gross lease acres in the Moquawkie area. The Company does not plan significant capital expenditures for 2002 in the Cook Inlet.

Gulf of Mexico

Overview In 2001, Anadarko significantly expanded its presence in the Gulf of Mexico, particularly in exploration lease blocks in deepwater for both sub-salt and conventional drilling. At year-end 2001, about 7% of the Company's proved reserves were located offshore in the Gulf of Mexico. Net production volumes in 2001 from these properties averaged 329 MMcf/d of gas and 24 MBbls/d of oil, condensate and NGLs. At



- 2001 DRILLING ACTIVITY
- ■ PRODUCTION BLOCKS
- □ DEVELOPMENT BLOCKS
- EXPLORATORY BLOCKS
- ☒ 2001 LEASE ACQUISITIONS
- 1999 TEXACO LEASE BLOCKS NOT ASSIGNED

OFFSHORE ACREAGE	**TEXAS**	**LOUISIANA**	**FLORIDA**	**MISSISSIPPI**	**CALIFORNIA**
UNDEVELOPED (Net)	300,840	380,331	42,710	165,784	2,785
DEVELOPED (Net)	33,209	182,456	—	3,996	—
PRODUCING WELLS (Net)	49	157	—	—	—

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year-end 2001, Anadarko owned an average 64% interest in 337 blocks representing 483,000 gross (220,000 net) acres in developed properties and 1,215,000 gross (890,000 net) acres in undeveloped properties in the Gulf of Mexico. Anadarko also holds options to earn working interests covering an additional 110 blocks. During 2001, Anadarko participated in 19 wells in the Gulf of Mexico: 12 shelf conventional, four sub-salt and three deepwater wells. Drilling results in the Gulf of Mexico included 11 gas wells, two oil wells and six dry holes for a success rate of 68%. Throughout the Gulf of Mexico, Anadarko has budgeted about $370 million for capital spending, which includes drilling 20 wells in 2002.

Shelf Conventional Shallow water projects in the Gulf of Mexico continue as the Company exploits the potential around several of its larger and more mature fields. Ongoing re-mapping and re-processing have generated numerous prospects, adding to the Company's large inventory of projects identified from extensive field studies. During 2001, nine discoveries were made. Workovers and recompletions were performed on several wells at the South Marsh Island (SMI) 281, Eugene Island 87 and SMI 268 fields.

Activity in 2001 was highlighted by the Company's continued success at SMI 280/281 (50% WI). Discovered in 1973, this is one of Anadarko's more mature offshore fields, but one that holds significant exploitation and deep exploration potential. During 2001, the SMI 280 #6 and SMI 280 #7 wells logged 267 and 254 feet of net pay, respectively. The SMI 280 #6 and #7 wells are expected to be flowing in the second quarter of 2002 at between 75 and 100 MMcf/d of gas production (gross). The Company has finished drilling the SMI 281 #8, #9 and #10 wells. Combined, these five wells are expected to add an additional 150 MMcf/d of gross gas production by year-end 2002.

Shallow water projects will continue to be an important part of Anadarko's Gulf of Mexico program. Anadarko has interests in a total of 110 blocks in its shelf program, with 45 prospects identified. In 2002, the Company is planning to drill nine development and nine exploratory wells near its older existing fields.

Sub-Salt During 2001, production continued from the Hickory (Grand Isle 110/111/116) and Tanzanite (Eugene Island 346) sub-salt fields discovered in 1998 off the coast of Louisiana. Currently, the Hickory field has three producing wells and Tanzanite has two producing wells. The Tanzanite field (100% WI) had total net production of 4 MMBbls of oil and 23 Bcf of natural gas in 2001. The Hickory field (50% WI) had total net production of 2 MMBbls of oil and 25 Bcf of natural gas in 2001.

At the end of 2001, the Company made a discovery with the Pardner well (100% WI), located on Mississippi Canyon 400/401 in about 1,200 feet of water. The well, drilled to a depth of 8,200 feet, encountered 92 net feet of oil pay in four intervals. The Company plans to sub-sea tie back the well and to bring it on-line in 2003.

During 2001, a sub-salt exploration well at the Tarantula prospect (100% WI), located on South Timbalier 308 in 480 feet of water, encountered about 170 feet of net pay. The #2 confirmation well was drilled and encountered 153 feet of net pay in five zones. A third well is being planned to optimize future development plans for Tarantula.

The Sazerac well (100% WI), a prospect located on Green Canyon Block 99, reached total depth at 16,700 feet in the down-dip sidetrack well. The well encountered some modest pay intervals in both the sidetrack and original wellbore. The Company believes that not enough pay is present to make this project economic.

The Eiger Sanction well (100% WI) is located on Mississippi Canyon Block 667 in 2,950 feet of water at the north end of the Gomez deepwater discovery. The original well and sidetracks reached a total depth of 25,900 feet in March 2002 and has encountered two potential pay intervals that were penetrated between 22,000 and 23,500 feet. They are not currently considered sufficient to economically develop. Further data evaluation will be ongoing in 2002 to determine future activity.

The Thunder well (30% WI), which is located on Eugene Island 341, was spudded in mid-December 2001 and is being drilled to a proposed depth of 20,000 feet. The well, located in 300 feet of water, is outside-operated and is expected to take 90 days to reach the total depth.

Anadarko has interests in a total of 122 blocks in its sub-salt program, with 19 prospects identified. An additional 20 blocks could be earned within its option program. One exploratory well and one development well are planned in the sub-salt for 2002. To date, eight of Anadarko's 16 sub-salt projects have resulted in discoveries. Four of these discoveries are commercial and already on production.

Deepwater Marco Polo (100% WI), Anadarko's first deepwater development project, is located on Green Canyon Block 608 about 150 miles offshore Louisiana in the Gulf of Mexico. Anadarko made the Marco Polo discovery in 2000 and has drilled a total of two wells and four sidetracks, which encountered between 90 and 360 feet of net oil and gas pay. Recently, the Company acquired the rights to explore and develop eight blocks in the Green Canyon area adjacent to the Marco Polo discovery. Anadarko plans to drill up to five wells on the complex of 11 blocks in 2002.

In December 2001, Anadarko signed a letter of intent with El Paso Energy Partners (EPN) under which a floating production platform capable of accommodating production from multiple fields, including production from Marco Polo, will be installed by EPN. The floating production platform will be stationed in 4,300 feet of water and will function as a hub. EPN and Cal Dive International, Inc. will own the platform and Anadarko will be the operator. Production capacity will be 100 MBbls/d of oil and 250 MMcf/d of gas. Under the proposed agreement, Anadarko will have firm capacity of 50 MBbls/d of oil and 150 MMcf/d of gas. The remainder of the platform capacity will be available to Anadarko for additional production and to third-parties who have fields developed in the area. Oil and gas processed on the platform will be transported through new gathering pipelines owned by EPN to downstream markets. The oil will be transported through a new 34-mile pipeline to the Ship Shoal 332 platform where onshore markets can be accessed. EPN intends to build a gas pipeline from the Marco Polo platform to Green Canyon Block 236 where onshore markets can be accessed.

The Company continued its deepwater exploration program in 2001. The Blues Image well (50% WI), located on Mississippi Canyon 587, had a proposed depth of 24,000 feet. The operator suspended operations at a depth of 15,000 feet due to a drilling problem. Anadarko is working with the operator on plans to resume drilling during 2002. The White Ash prospect (100% WI), located on Mississippi Canyon Block 392 in nearly 7,300 feet of water, was drilled to gain information prior to Anadarko going to a lease sale. The well reached a total depth of 18,225 feet and was a dry hole, but provided useful information to adjust the Company's bidding strategy. The Lisa Anne exploratory well (100% WI), located on Green Canyon Block 474, was recently drilled to a depth of 13,279 feet, but was unsuccessful.

Anadarko holds a total of 105 lease blocks in its deepwater program and has identified 29 prospects. An additional 98 blocks could be earned within its option program. During 2001, the Company significantly increased its exploration acreage in the deepwater through the South Auger Participation Agreement and success at lease sales.

South Auger Participation Agreement During 2001, Anadarko entered into a Participation Agreement with BP to explore 95 deepwater blocks held by BP in the Garden Banks and Keathley Canyon areas of the western Gulf of Mexico. The 95 blocks, held 100% by BP, are within a larger 640-block area of mutual interest where the two companies will license and reprocess 3-D seismic data. These blocks are in water depths ranging from 3,000 to 6,000 feet. The agreement gives Anadarko the option to earn a 33% to 66% working interest in the blocks. Anadarko will fund 100% of the licensing and re-processing costs and pay a disproportionately larger share of the first four wells drilled. Also, as part of the agreement, BP assigned Anadarko its rights in eight blocks in the Green Canyon area near the Company's Marco Polo discovery.

Lease Sales Anadarko participated in the OCS Federal Lease Sale 178 held in March 2001 and acquired 23 tracts covering 120,000 acres in the Gulf of Mexico. The blocks, which represent an investment of $32 million for Anadarko, include seven blocks on the Outer Continental Shelf in shallow water and 16 blocks in deepwater.

Anadarko also acquired 26 tracts (100% WI) in the Western Gulf of Mexico Lease Sale 180 held in August 2001. The Company's total investment was about $6 million. The tracts cover more than 133,000 acres in deepwater, mainly around the Port Isabel and Alaminos Canyon areas.

In January 2002, Anadarko acquired 26 tracts (100% WI) in the Eastern Gulf of Mexico Lease Sale 181. The Company's total investment was about $136 million. The 26 tracts cover nearly 150,000 acres in water depths ranging from 7,000 to 9,500 feet. The blocks included in Sale 181 have not been available for exploration since 1988, long before major advancements occurred in seismic imagery and deepwater drilling and development technology. Mapped prospects on these blocks may potentially hold substantial oil and gas reserves. The Company is considering taking on partners to recover lease costs and reduce risk. Exploration drilling is expected to take place in 2003.

Gas Processing

The Company processes gas at various third-party plants under agreements generally structured to provide for the extraction and sale of NGLs in efficient plants with flexible commitments. The Company has agreements with four plants in the western states area, 14 plants in the mid-continent area and 10 plants in the gulf coast area. Anadarko also processes gas and has interests in one Company-operated plant and three non-operated plants in the western states. Anadarko's strategy to aggregate gas through Company-owned and third-party gathering systems allows Anadarko to secure processing arrangements in each of the regions where the Company has significant production.

Properties and Activities — Canada

Overview Anadarko's Canadian operations were acquired in July 2000 with the RME merger transaction and further expanded in March 2001 with the purchase of Canadian-based Berkley Petroleum Corp. The Berkley acquisition increased Anadarko's Canadian reserves by 42% and total acreage position from three million to nearly five million net acres. Since the Berkley acquisition, Anadarko has added an additional 550,000 acres for a net total of 5,262,000 acres.

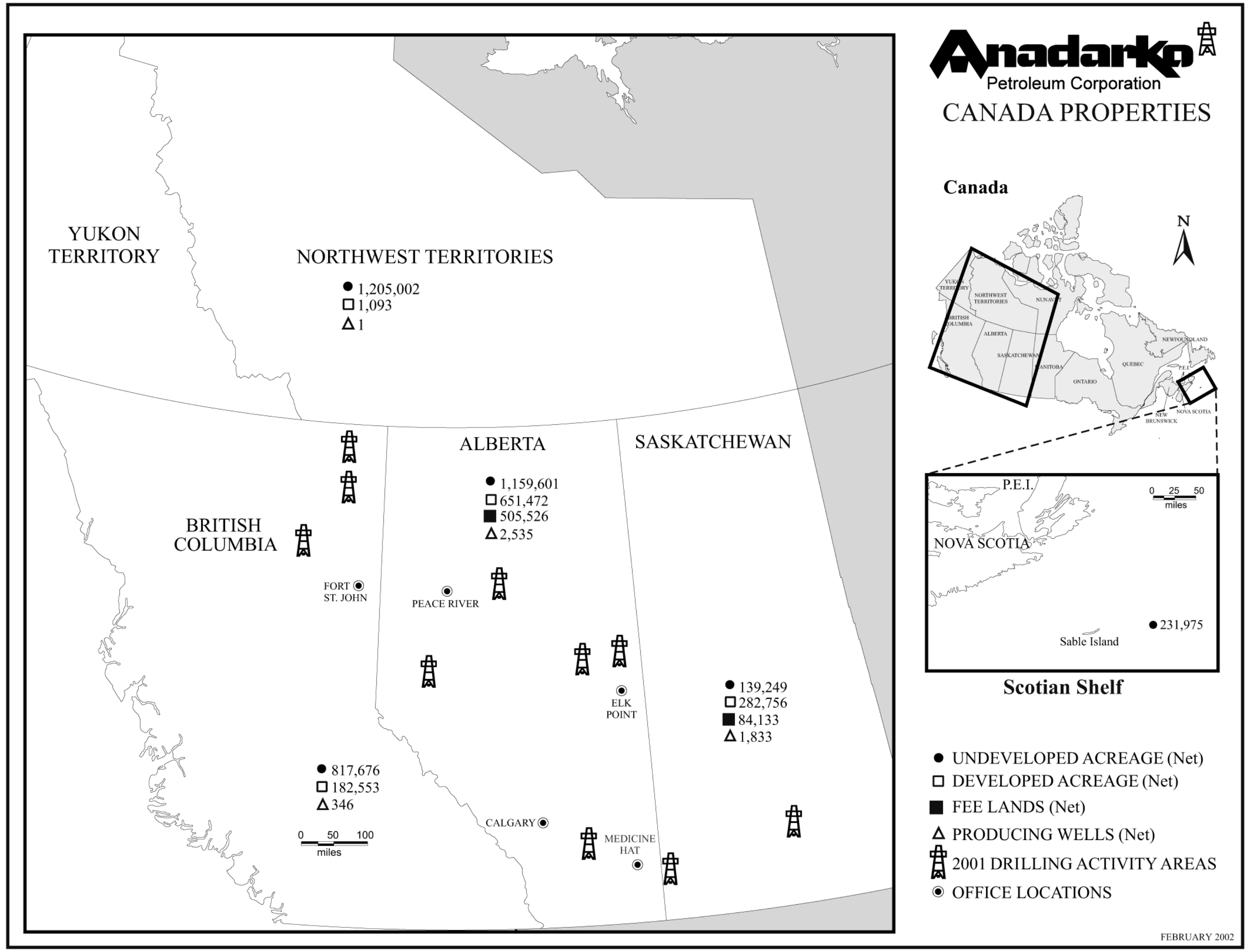
Anadarko has operations in Alberta, northeast British Columbia, Saskatchewan and the Northwest Territories of Canada. The Company has proved reserves in Canada of 315 MMBOE, which includes 1.2 Tcf of gas and 108 MMBbls of crude oil, condensate and NGLs. In 2001, net production from the Company's properties in Canada averaged 331 MMcf/d of gas and 38 MBbls/d of crude oil, condensate and NGLs, or 17% of the Company's total production volumes.

At year-end 2001, Anadarko had 22 rigs under contract and seven Company-operated exploratory wells plus five non-operated wildcat wells were drilling. Anadarko reached a peak of 25 rigs drilling in Canada in the 2001-2002 winter season. During 2001, Anadarko participated in 476 wells with a 94% success rate, including 285 gas wells and 162 oil wells. Anadarko has 9,102,000 gross (3,554,000 net) undeveloped lease acres, 1,942,000 gross (1,118,000 net) developed lease acres and 590,000 gross (590,000 net) fee acres in Canada. The Company's 2002 oil and gas capital budget of $255 million for Canada includes approximately $190 million for development drilling and infrastructure projects that are expected to increase production primarily in northeast British Columbia and northern Alberta. The budget also includes $65 million for exploration which will include drilling approximately 50 exploration wells. The accompanying map illustrates the Company's developed, undeveloped and fee acreage, number of productive wells and other data relevant to its properties in Canada.

Northwest Territories In the Mackenzie Delta, Anadarko and its partners conducted a 2-D seismic survey of approximately 620 miles in early 2001. Acquisition of a 130 square mile 3-D seismic program over this block commenced in January 2002. The Company holds about 400,000 net acres in the Mackenzie Delta/Beaufort Sea region.

In the southern territories, Anadarko completed a deal in 2001 to explore on several exploration licenses in the Fort Liard sub-basin. Under the agreement, Anadarko will acquire 3-D and 2-D seismic in the 2001-2002 winter season and drill a test well the following year with the potential to earn an interest, via rolling options, in up to 71,000 acres. The seismic programs are expected to be completed by the end of March 2002. Additionally in Fort Liard, two Bovie Slave Point wildcat wells (50% WI) spudded in late 2001 and reached total depth in early 2002. Both wells are pending completion. A third Slave Point exploratory well (100% WI) will begin drilling in early 2002.

British Columbia In 2001, Anadarko drilled, completed and tied-in the Altares C-15-I exploration well (100% WI). This Mississippian formation well came on-line at 5 MMcf/d of gas. Six follow-up leads have been identified. The first of two exploratory wells spudded in December 2001 on a similar play concept to the initial discovery. The well is expected to reach total depth by the end of the first quarter 2002. The Company will evaluate seismic over 24 sections (15,300 acres) and then drill a test well to earn an interest in eight sections and a similar option on the remaining acreage. Another exploration well, the Green A-55-A (100% WI), was drilled in the Buckinghorse prospect area in 2001 and flowed at a rate of 4 MMcf/d of gas.


Anadarko
Petroleum Corporation
CANADA PROPERTIES
Canada
N
YUKON TERRITORY
NORTHWEST TERRITORIES
1,205,002
1,093
1
BRITISH COLUMBIA
817,676
182,553
346
ALBERTA
1,159,601
651,472
505,526
2,535
SASKATCHEWAN
139,249
282,756
84,133
1,833
FORT ST. JOHN
PEACE RIVER
ELK POINT
CALGARY
MEDICINE HAT
0 50 100
miles
P.E.I.
NOVA SCOTIA
0 25 50
miles
231,975
Sable Island
Scotian Shelf
UNDEVELOPED ACREAGE (Net)
DEVELOPED ACREAGE (Net)
FEE LANDS (Net)
PRODUCING WELLS (Net)
2001 DRILLING ACTIVITY AREAS
OFFICE LOCATIONS
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Additional drilling and tie-in activity in northeast British Columbia took place in the Graham/Chowade field (60% WI) during 2001. Compression was also added in the field resulting in 5 MMcf/d of incremental gas production to a total of 27 MMcf/d of gas.

In the Sukunka area of the British Columbia Foothills, Anadarko is participating in a high impact exploratory well (30% WI), which is a 15,000 foot deep Mississippian test. Well results are expected by the end of the second quarter 2002.

In Anadarko's Jean Marie play in northeast British Columbia, the Company increased its acreage position by over 100,000 acres to approximately 200,000 net acres in 2001. In 2001, the Company completed a total of nine horizontal wells at a combined initial production rate of 6 MMcf/d of gas.

Alberta In northwest Alberta, two successful Slave Point oil wells were drilled, offsetting the Dawson 13-2 well (90% WI), a Slave Point new pool discovery which tested 1,138 Bbls/d of oil. The Dawson 3-11 (90% WI) and Dawson 11-11 (90% WI) tested at a rate of 1,200 Bbls/d and 530 Bbls/d of oil, respectively. Additionally, in a separate pool, two Dawson field development wells were completed. The Dawson 8-8 tested at a rate of 1,200 Bbls/d of oil and the Dawson 16-7 tested at a rate of 1,800 Bbls/d of oil. Anadarko plans to drill an additional 30 wells in the Dawson area in 2002.

In the Saddle Hills area of northern Alberta, the 15-28 discovery well (100% WI) tested 6 MMcf/d of gas and is expected to begin producing in the first quarter of 2002. Based on this exploration success, Anadarko plans to drill three offset wells in 2002 and pursue similar exploration opportunities.

In north central Alberta, in the Wild Hay area, up to five rigs were active during the fourth quarter of 2001. In this deep basin gas play with multi-pay potential, Anadarko achieved a 100% success rate for 2001 in a 27 well program.

Anadarko also completed a 30 MMcf/d of gas expansion of the Wild Hay Gas Plant (100% WI) late in 2001, increasing total capacity to 53 MMcf/d of gas.

Activity continued in Anadarko's heavy oil area in northeast Alberta where 123 wells were drilled and 101 wells were recompleted. Production averaged 20 MBbls/d of oil (net) during 2001.

Saskatchewan The Company drilled and completed 215 wells and recompleted 87 wells in the Hatton shallow gas play in southwest Saskatchewan during 2001, adding 12 MMcf/d of net gas production. The Company expects to drill about 100 wells in 2002.

In southeast Saskatchewan, two high volume horizontal oil wells in the Steelman pool tested 2 MBbls/d of oil and 800 Bbls/d of oil respectively, from the Devonian Winnipegosis formation. Two additional horizontal wells are planned for the Steelman area in the first quarter of 2002.

Properties and Activities — Algeria

Overview Anadarko is actively developing oil fields discovered by the Company in Algeria's Sahara Desert. Since 1989, Anadarko has participated in 79 productive wells (12 exploration and 67 delineation/development) and has submitted detailed development plans (called Commerciality Reports) for 12 fields in Algeria. The Company has proved reserves in Algeria of 387 MMBbls of crude oil as of year-end 2001. Activity in 2001 was highlighted by significant development progress with the addition of 150 MBbls/d of production capacity, as well as Anadarko's return to exploration in Algeria. In 2001, Anadarko participated in 19 wells with a success rate of 95% — 18 oil wells and one unsuccessful well. Anadarko plans to invest about $160 million in Algeria in 2002. At the end of 2001, the Company had 3,596,000 gross (1,226,000 net) acres in Algeria. The accompanying map illustrates the Company's developed and undeveloped acreage, number of productive wells and other data relevant to its properties in Algeria.

Contracts/Partners Anadarko's interest in the original production sharing agreement (PSA) is 50% before participation at the exploitation stage by **SONATRACH,** the national oil and gas enterprise of Algeria. The Company has two partners, each with a 25% interest in the Algerian venture, also prior to participation by **SONATRACH;** they are LASMO Oil (Algeria) Limited, a wholly-owned subsidiary of ENI-Agip, and Maersk Olie Algeriet AS, a wholly-owned subsidiary of Maersk Olie Og Gas AS, a company in the Danish A.P. Moller group. Under the terms of the PSA, oil reserves that are discovered, developed and produced will

Anadarko Petroleum Corporation

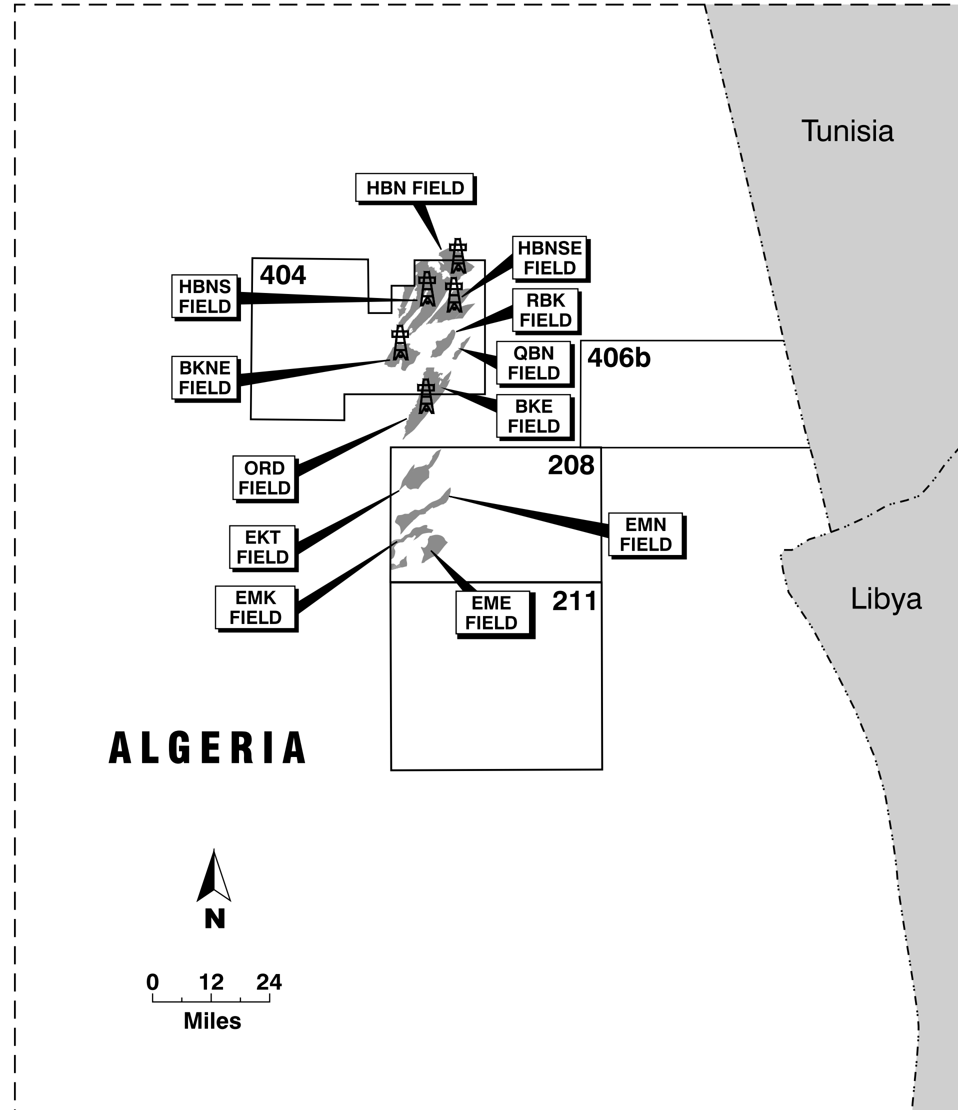
ALGERIA PROPERTIES

Algeria Undeveloped Acreage
Total 3.4 million acres (1.2 million acres net)

Algeria Developed Acreage (HBNS, HBN, ORD, HBNSE, BKNE, RBK, QBN & BKE Fields)
Total 209,000 acres (51,000 acres net)

Productive Wells
Total 79 (20 net)

Fields discovered to date
2001 Drilling activity areas
Anadarko operated blocks



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be shared by **SONATRACH,** Anadarko and its two partners. Anadarko and its partners funded **SONATRACH's** 51% share of exploration costs and are entitled to recover these exploration costs out of production in the exploitation phase. As of year-end 2001, Anadarko and its partners had recovered about 44% of **SONATRACH's** portion of exploration costs through an increased share of production of cost-recovery oil with the majority of the remaining 56% expected to be recovered by early 2003. **SONATRACH** is responsible for 51% of development and production costs. During 2000, **SONATRACH** and Anadarko formed a non-profit company, Groupement Berkine, to carry out their joint operating activities under the PSA. **SONATRACH** and Anadarko fund the expenditures incurred by Groupement Berkine according to their participating interests under the PSA. **SONATRACH** has owned shares of the Company's common stock since 1986 and at year-end 2001 was the beneficial owner of 5% of Anadarko's outstanding common stock.

In 2001, Anadarko and its partners signed an amendment to the PSA with **SONATRACH**, which allows exploration to resume on Blocks 404, 208 and 211. The exploration phase of the original PSA ended in 1998. While the terms of the amendment are not as favorable as the terms of the original agreement, the Company still considers the terms attractive. The Company also signed a separate exploration license, in which Anadarko has a 100% interest, for Block 406b at Algeria's licensing round in 2001.

Development First oil production began in May 1998, from facilities at the Hassi Berkine South (HBNS) field. Production from a second processing unit for the HBNS field began in August 2001. Oil produced from the HBNS field is sold as Saharan Blend, a high quality crude that provides refiners with large quantities of premium products such as jet and diesel fuel. Production from the HBNS field averaged 77 MBbls/d of oil (gross) in 2001 compared to 68 MBbls/d of oil (gross) in 2000.

SONATRACH and Anadarko are developing the Hassi Berkine (HBN) field just north of the HBNS field. A crude oil production train with the capacity to process 75 MBbls/d of oil, as well as a gathering system, injection lines and facilities for crude oil storage and export have all been installed as part of the facility expansion. Production from this third processing unit began on December 23, 2001 — two months ahead of schedule. Having the HBN field on-line increases the nominal oil production capacity of the central processing facility to 210 MBbls/d. The HBN field is located across Block 404 and Block 403 and will be unitized between two associations. Development costs and production sharing will be 74.5% for the Anadarko/**SONATRACH** Association on a preliminary basis. This percentage is subject to future redetermination.

A fourth production train, currently under construction at the HBNS complex, will process production from the Block 404 satellite fields — Hassi Berkine South East (HBNSE), Rhourde Berkine (RBK), Qoubba North (QBN), Berkine Northeast (BKNE) and Berkine East (BKE). First production from this fourth unit is expected in the second quarter of 2002 and should increase total oil production capacity by an additional 75 MBbls/d to 285 MBbls/d of oil.

Anadarko is also actively involved in developing the Ourhoud (ORD) field. The facilities for this field will have a capacity of 230 MBbls/d of oil (gross) when completed. Production from the first train is expected in early 2003. The contract calls for the construction of three oil production trains, as well as water injection and gas processing and injection facilities, a field gathering system and crude oil storage and shipping installations.

Located in the southern portion of Block 404, the ORD field extends into Block 406a and Block 405 and consequently will be unitized with the companies in those Blocks. The preliminary allocation of development and production costs to the Anadarko/**SONATRACH** Association on Block 404 is 37.5%. This percentage is subject to future redetermination. Anadarko, Maersk, Lasmo, Cepsa, Burlington Resources and Talisman Energy are participating in development work on the field in partnership with **SONATRACH.** To date, a total of 19 productive development wells have been drilled in the ORD field and development drilling will continue in 2002.

Anadarko also has several fields further south on Block 208; these include the El Merk field (EMK), the El Kheit Et Tessekha field (EKT), the El Merk East field (EME) and the El Merk North field (EMN). Initial development plans for these more recent discoveries were submitted in 1998 and are being finalized. Design work has begun, and these production facilities are expected to be built in the future.

Exploration The PSA, as amended in 2001, allows Anadarko and its partners to resume exploration on the three blocks outside of the exploitation license boundaries encompassing the previous discoveries. These are the same blocks Anadarko and its partners began exploring in 1989 and the new agreement allows Anadarko to build on the knowledge gathered since then using current state-of-the-art technology to commence a new phase of exploration.

Under the terms of the three-phase exploration program, Anadarko and its partners will spend a minimum of $55 million. During the first five years, 400 square kilometers of 3-D seismic and 1,100 kilometers of 2-D seismic will be acquired and processed; the results of previous seismic surveys will be reprocessed; and six exploration wells will be drilled. Work has commenced on reprocessing the existing 2-D seismic database and acquisition is underway for 1,100 kilometers of new 2-D seismic. Exploration drilling is expected to begin during 2002. Should the sixth- and seventh-year options be exercised, an additional exploration well will be drilled in each year. Anadarko and its partners will finance 100% of the exploration investment and **SONATRACH** will participate 51% in the development and exploitation phases of any discoveries. Where appropriate, existing facilities and infrastructure may be used to develop any discoveries, thereby reducing development costs and potentially accelerating first oil production.

The license for Block 406b has a three-year initial term. A work program commitment includes seismic acquisition and one exploration well. Anadarko has a 100% interest in this 686,000 acre block, which is located in the Berkine basin to the east of Anadarko's other license areas. The Company now controls a total of 3,596,000 acres in this region of the Sahara.

Political unrest continues in Algeria. Anadarko is closely monitoring the situation and has taken reasonable and prudent steps to ensure the safety of employees and the security of its facilities in the remote regions of the Sahara Desert. Anadarko is presently unable to predict with certainty any effect the current situation may have on activity planned for 2002 and beyond. However, the situation has not had any material effect to date on the Company's operations. See *Regulatory Matters and Additional Factors Affecting Business — Foreign Operations Risk* under Item 7 of this Form 10-K.

Properties and Activities — Other International

Overview The Company's other international oil and gas production and development operations are located primarily in Venezuela, Qatar and Oman. The Company also has less significant international oil and gas operation activities, including interests in two non-operated offshore producing properties in Australia and a producing interest in a non-operated property in Egypt. The Company currently has exploration projects in Tunisia, the Middle East, West Africa, Australia, the Faroe Islands, off the coast of Georgia in the Black Sea and other selected areas.

The Company has total proved reserves in these other international locations of 164 MMBbls of crude oil, condensate and NGLs and 146 Bcf of gas at year-end 2001. During 2001, net production from the Company's other international properties was 4 MMcf/d of gas and 36 MBbls/d of crude oil, condensate and NGLs, or 7% of the Company's total production volumes. Anadarko participated in a total of 31 wells in its other international locations during 2001 with a success rate of 84%. Drilling results included 25 oil wells, one gas well and five dry holes. Anadarko has 29,981,000 gross (15,314,000 net) undeveloped lease acres and 427,000 gross (87,000 net) developed lease acres in these international areas. See *Regulatory Matters and Additional Factors Affecting Business — Foreign Operations Risk* under Item 7 of this Form 10-K.

Venezuela The Company's Venezuelan operation was acquired with the RME merger and consists of the Oritupano-Leona concession, which is a risk service contract. The Oritupano-Leona Block, in which the Company has a 45% participating interest, covers 395,000 acres and had approximately 276 producing wells at year-end 2001. Oil production from the block reached a record level of 53 MBbls/d of oil in December 2001 and averaged 48 MBbls/d of oil (22 MBbls/d net) during 2001. For 2001, net production volumes totaled 8 MMBOE. The active development/exploitation program in 2001 included 19 new well completions and 50 well reactivations. The operator and Anadarko are finalizing plans for a reduced drilling program in 2002 due to current economic and industry conditions.

Middle East During 2001, the Company acquired Gulfstream Resources Canada Ltd. for a total value of $118 million plus the assumption of $10 million of debt. Anadarko believes the Gulfstream assets, concentrated in Qatar and Oman, have production growth opportunities and exploration upside.

Qatar Anadarko has a 65% interest in the Al Rayyan field, which is part of an Exploration and Production Sharing Agreement covering offshore Qatar Blocks 12 and 13. Production from the Al Rayyan field, located on offshore Block 12, averaged 4 MBbls/d of oil net during the fourth quarter of 2001. A redevelopment program, which includes increasing existing facility capacity and drilling horizontal wells, is underway and production is expected to increase to 35 MBbls/d of oil (13 MBbls/d net) in early 2003. A six-leg jack-up rig was purchased and the decks were cleared for conversion to a permanent production facility with the capacity of 45 MBbls/d of oil. Approximately $80 million is budgeted in 2002 for construction of production facilities, development drilling in the Al Rayyan field, and an exploration well on Block 12. Block 13, was removed from a force majeure status as the result of a boundary settlement between Qatar and Bahrain in March 2001. During 2002, the Company plans to initiate geological and geophysical technical work on Block 13.

Anadarko also has a 49% interest in an exploration and production sharing agreement covering offshore Block 11. Two exploratory wells drilled on Block 11 during 2001 found the objective wet and have been plugged and abandoned. Evaluation is underway to determine the potential for any further exploratory work on Block 11.

Oman Anadarko, the operator, drilled a horizontal step-out well in the Hafar field in Block 30 during 2001. Evaluation of well tests is currently being conducted. One existing well on the block was re-entered and flow tested during the fourth quarter of 2001. The development plans will be finalized based on the results of the well tests. Anadarko has a 100% interest in the field. Gas production will be sold to the Oman government under a long-term sale agreement.

Egypt Anadarko has a 25% non-operated interest in a producing field offshore Egypt named Zaafarana. Average net sales volumes for 2001 were 950 Bbls/d of oil.

Brazil Anadarko is the operator and has a 90% interest in the SES 107 Block, which was acquired with the RME merger. In 2001, Anadarko relinquished its acreage in the BT Seal 101 Block.

Australia Anadarko has a 15% interest in outside-operated production facilities in the Jabiru and Challis fields. The Company's net sales volumes from the Jabiru and Challis fields during 2001 were 356 MBbls of oil. Anadarko also has agreements on three licenses (AC/P 25, 26 and 27) in the Timor Sea, Northwest Shelf of Australia. Anadarko drilled one well on each license area in the first quarter of 2002, all of which were unsuccessful.

Tunisia The Company has a 47% interest and is the operator of the 1.1 million acre Anaguid block in the Ghadames basin of Tunisia, which will revert to a 24% interest if ETAP (Tunisia's national oil company) exercises its option to back into the project. The acreage is on trend with the Company's discoveries in Algeria to the west and it holds the potential for the discovery of Triassic and Silurian oil fields. In 2001, the first of two available extension periods was granted, allowing time for the integration of the most recent seismic surveys, in preparation for the forthcoming exploration drilling program.

Just south of the Anaguid permit, Anadarko holds a 50% interest in the Jenein Nord block prior to back-in by ETAP. During 2001, two 2-D seismic surveys were acquired in the southeast and northern areas of the permit.

In 2000, Anadarko negotiated an option to explore the Sanrhar concession, which is surrounded by the Anaguid permit. In 2001, as part of the Anaguid seismic program, additional seismic data was acquired in Sanrhar.

In 2002, Anadarko will further evaluate the most recently acquired seismic surveys to finalize the prospect inventory ahead of a forthcoming exploration drilling program.

West Africa Anadarko operates the Marine IX Block offshore the Republic of Congo with a 47% interest. Anadarko and partners have approved and scheduled the drilling of the Rita prospect on this block. Rita is an amplitude-supported prospect with significant reserve potential. The Company expects to spud the well, located in 4,400 feet of water, during the second quarter of 2002.

Anadarko is also the operator and holds a 50% interest in the Agali Block offshore Gabon. 3-D seismic data, acquired in 2001, will be processed and evaluated during 2002. Drilling is not expected to occur until 2003.

North Atlantic Margin In the Faroe Islands, Anadarko is the operator and sole licensee of License 007 and holds a 28% interest in the outside-operated License 006. The licenses cover a total of 618,000 acres. In 2001, Anadarko operated and participated in both a conventional long-offset seismic program and a sub-basalt seismic imaging trial survey. The Company also acquired a proprietary seismic survey and participated in a marine magnetotellurics program. In 2002, the Company plans to fully integrate this data as part of a comprehensive license and basin evaluation.

In 2001, Anadarko participated in an unsuccessful exploration well in Tranche 21 (20%), located west of Britain on the United Kingdom Continental Shelf (UKCS). The first exploration periods for UKCS Tranches 21, 61 and 63, where the Company's interests are 20%, 8% and 50%, respectively, are due to expire in April 2002. Certain acreage in Tranche 61 is expected to be retained.

Georgia — Black Sea Anadarko has a Production Sharing Contract with the State of Georgia. The agreement gives Anadarko exploration rights to three blocks covering approximately two million acres on the Black Sea continental shelf and extending 50 miles offshore. In 2001, the Company completed the processing and interpretation of about 1,400 miles of seismic data that was acquired in 2000 and conducted additional geological and geophysical analyses. In 2002, the Company plans to seek a partner to possibly drill wells in the future.

Guatemala and Argentina In 2001, the Company sold its wholly-owned subsidiary, Basic Resources International (Basic), for $120 million. Basic produces and refines crude oil in Guatemala. In 2001, the Company also sold its interest in Argentina for $16 million. The sales were part of the Company's ongoing strategy to divest low-margin, low-growth projects in its portfolio.

Drilling Programs

The Company's 2001 drilling program focused on known oil and gas provinces in the United States (Lower 48, Gulf of Mexico and Alaska), Canada and Algeria. Exploration activity consisted of 122 wells, including 58 wells in the Lower 48, 8 wells in Alaska, 8 wells offshore in the Gulf of Mexico, 43 wells in Canada and 5 wells at other international locations. Development activity consisted of 1,298 wells, which included 797 wells in the Lower 48, 12 wells in Alaska, 11 wells offshore in the Gulf of Mexico, 433 wells in Canada, 19 wells in Algeria and 26 wells at other international locations.

Drilling Statistics

The following table shows the results of the oil and gas wells drilled and tested:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2001							
United States	**33.6**	**18.3**	**51.9**	**544.0**	**8.4**	**552.4**	**604.3**
Canada	**28.0**	**6.0**	**34.0**	**381.1**	**18.0**	**399.1**	**433.1**
Algeria	**—**	**—**	**—**	**3.5**	**0.2**	**3.7**	**3.7**
Other International	**—**	**2.7**	**2.7**	**11.4**	**—**	**11.4**	**14.1**
Total	**61.6**	**27.0**	**88.6**	**940.0**	**26.6**	**966.6**	**1,055.2**
2000							
United States	12.9	9.0	21.9	390.8	10.4	401.2	423.1
Canada	8.9	8.0	16.9	98.1	14.4	112.5	129.4
Algeria	—	—	—	1.7	—	1.7	1.7
Other International	—	0.6	0.6	5.7	—	5.7	6.3
Total	21.8	17.6	39.4	496.3	24.8	521.1	560.5
1999							
United States	8.4	3.5	11.9	125.6	15.7	141.3	153.2
Algeria	—	—	—	1.9	—	1.9	1.9
Other International	—	1.4	1.4	—	—	—	1.4
Total	8.4	4.9	13.3	127.5	15.7	143.2	156.5

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 as of December 31, 2001:

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion	
	Exploration	Development	Exploration	Development
United States				
Gross	19	67	8	39
Net	15.0	52.5	2.9	26.5
Canada				
Gross	12	—	4	30
Net	12.0	—	3.0	27.6
Algeria				
Gross	—	2	—	—
Net	—	0.5	—	—
Other International				
Gross	—	2	—	—
Net	—	1.2	—	—
Total				
Gross	31	71	12	69
Net	27.0	54.2	5.9	54.1

Productive Wells

As of December 31, 2001, the Company owned productive wells as follows:

	Oil Wells*	Gas Wells*
United States		
Gross	6,996	10,716
Net	4,285	6,661
Canada		
Gross	3,497	3,883
Net	1,883	2,832
Algeria		
Gross	79	—
Net	20	—
Other International		
Gross	303	—
Net	133	—
Total		
Gross	10,875	14,599
Net	6,321	9,493

* Includes wells containing multiple completions as follows:

Gross	617	2,186
Net	488	1,730

Marketing and Gathering Properties and Activities

Marketing The Company, primarily through Anadarko Energy Services (AES), markets its natural gas, crude oil and NGLs production. In addition, AES seeks opportunities to capture additional value through downstream trading of energy-related products and services. In this capacity, AES purchases third-party production, utilizes transportation, storage and other energy-related contracts or facilities. Third-party purchases allow the Company to aggregate larger volumes of gas and attract larger, more creditworthy customers, which in turn spreads the Company's relatively fixed overhead costs over more gas and can help to reduce transportation costs. AES does not engage in market making practices nor does it trade in non-energy-related commodities.

Gas Gathering Anadarko owns and operates six major gas gathering systems in the nation's mid-continent area, where the Company has substantial gas production. The systems are: Antioch Gathering System in the Southwest Antioch field of Oklahoma; Sneed System in the West Panhandle field of Texas; Hugoton Gathering System in southwest Kansas; Dew Gathering System in east Texas; Pinnacle Gathering System in east Texas; and CJV Gathering System in the Carthage field of east Texas.

The Company's major gathering systems have more than 2,700 miles of pipeline connecting about 3,100 wells and averaged more than 680 MMcf/d of gas throughput in 2001. In addition, Anadarko operates numerous other smaller gas gathering systems.

Anadarko purchased Pinnacle Gas Treating, Inc. for $38 million in January 2001. The purchase gives Anadarko ownership of a natural gas gathering system that runs through the heart of its Bossier properties. The network, which has a capacity of 500 MMcf/d of gas, consists of 60 miles of large-diameter pipe, 40 miles of small-diameter laterals and spurs in addition to a 60-mile fuel redelivery system. The Bethel treating plant acquired in the transaction removes carbon dioxide and hydrogen sulfide from gas and can handle as much as 500 MMcf/d of gas. In 2001, Anadarko expanded the Bethel plant to accommodate growing volumes in the area.

Minerals Properties and Activities

The Company's minerals operations were acquired in the RME merger transaction. The minerals operations contribute to the Company's operating income through non-operated joint venture and royalty arrangements in coal, trona and industrial mineral mines across the Company's extensive fee mineral interest in the Land Grant. The Company reinvests the cash flow from its hard minerals operations primarily into its oil and gas operations.

The Company's low sulfur coal deposits, located primarily in southern Wyoming, compete with other western coal producers for industrial and utility boiler markets, which burn the coal to produce steam used to generate electricity. Most of the Company's coal interests use the surface mining method of extraction. The Company's coal interests are served by a single rail line and incur greater transportation costs than some of its competitors in the western United States. Additionally, competing western coal companies in the Powder River basin in Wyoming have lower mining costs than the Company's coal interests. Because of the higher extraction and transportation costs compared to Powder River basin coal, additional development of the Company's reserves is dependent on increased coal usage in local markets. In addition to fee mineral ownership of and royalty interests in coal reserves, the Company owns a 50% non-operating interest in Black Butte Coal Company. Black Butte Coal Company produces approximately three million tons of coal per year.

The world's largest deposit of trona, comprising 90% of the world's known trona resources, is located in the Green River basin in southwestern Wyoming. Natural soda ash, which is produced by refining trona ore, is used primarily in the production of glass, in the paper and water treatment industries and in the manufacturing of certain chemicals and detergents. All of the reserves that can be mined in the Company's trona deposit lie within the Land Grant and adjoining lands. The Company owns interests in lands containing approximately 50% of these reserves and has leased a portion of those lands to companies that mine and refine trona. Natural soda ash from Wyoming contributes 25% of the world's soda ash supply with the remainder principally from synthetic processes. In addition to fee mineral ownership of and royalty interest in trona reserves, the Company owns a 49% non-operating interest in the OCI Wyoming LP soda ash refining facility near Green River, Wyoming. Among domestic producers, this facility is ranked second in soda ash capacity producing over three million tons per year.

Segment and Geographic Information

Information on operations by segment and geographic location is contained in *Note 11* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Employees

As of December 31, 2001, the Company had about 3,500 employees. Relations between the Company and its employees are considered to be satisfactory and the Company has had no significant work stoppages or strikes.

Regulatory Matters and Additional Factors Affecting Business

See *Regulatory Matters and Additional Factors Affecting Business* under Item 7 of this Form 10-K.

Title to Properties

As is customary in the oil and gas industry, only a preliminary title examination 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. A thorough title examination has been performed with respect to substantially all leasehold producing properties owned by the Company. Anadarko believes the title to its leasehold properties is good and defensible in accordance with standards generally acceptable in the oil and gas industry subject to such exceptions which, in the opinion of counsel employed in the various areas in which the Company has conducted exploration activities, 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.

Capital Spending

See *Capital Resources and Liquidity* under Item 7 of this Form 10-K.

Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Stock Dividends

As a result of the Company's net loss in 2001, Anadarko's earnings did not cover fixed charges by $599 million and did not cover combined fixed charges and preferred stock dividends by $610 million. Anadarko's ratios of earnings to fixed charges for the years ended December 31, 2000 and 1999 were 7.35 and 1.77, respectively. The Company's ratios of earnings to combined fixed charges and preferred stock dividends for the years ended December 31, 2000 and 1999 were 6.80 and 1.53, respectively.

These ratios were computed by dividing earnings by either fixed charges or combined fixed charges and preferred stock dividends. For this purpose, earnings include income before income taxes and fixed charges. Fixed charges include interest and amortization of debt expenses and the estimated interest component of rentals. Preferred stock dividends are adjusted to reflect the amount of pretax earnings required for payment.

Item 2. Properties

See information appearing under Item 1 of this Form 10-K.

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 numerous claims by employees of third-party contractors alleging exposure to asbestos and benzene while working at a refinery in Corpus Christi, Texas, which RME sold in segments in 1987 and 1989. 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 of the Company, although results of operations and cash flow could be significantly impacted in the reporting periods in which such matters are resolved. Discussed below are several specific proceedings.

Royalty Litigation During September 2000, the Company was named as a defendant in a case styled *U.S. of America ex rel. Harold E. Wright v. AGIP Company, et al.* (the "Gas Qui Tam case") filed in the U.S. District Court for the Eastern District of Texas, Lufkin Division. This lawsuit generally alleges that the Company and 118 other defendants improperly measured and otherwise undervalued natural gas in connection with a payment of royalties on production from federal and Indian lands. The case has been transferred to the U.S. District Court, Multi-District Litigation Docket pending in Wyoming. Based on the Company's present understanding of the various governmental and False Claims Act proceedings described above, the Company believes that it has substantial defenses to these claims and intends to vigorously assert such defenses. However, if the Company is found to have violated the False Claims Act, the Company could be subject to a variety of sanctions, including treble damages and substantial monetary fines.

A group of royalty owners purporting to represent RME's gas royalty owners in Texas (*Neinast, et al.*) was granted class action certification in December 1999, by the 21st Judicial District Court of Washington County, Texas, in connection with a gas royalty underpayment case against the Company. This certification did not constitute a review by the Court of the merits of the claims being asserted. The royalty owners' pleadings did not specify the damages being claimed, although most recently a demand for damages in the amount of $100 million has been asserted. The Company is of the opinion that the amount of damages at risk is substantially less than the amount demanded by the class action counsel and the Company intends to vigorously assert its defenses. The Company appealed the class certification order. A favorable decision from the Houston Court of Appeals decertified the class. It is anticipated that the royalty owners will now appeal this matter to the Texas Supreme Court.

A class action lawsuit entitled *Gilbert H. Coulter, et al. v. Anadarko Petroleum Corporation* has been certified in the 26th Judicial District Court, Stevens County, Kansas. In this action, the royalty owners contend that royalty was underpaid as a result of the deduction for certain post-production costs in the calculation of royalty. The Company believes that its method of calculating royalty was proper and that its gas was marketable in the condition produced, and thus plaintiffs' claims are without merit. This case was certified as a class action in August 2000 and was tried in February 2002. A decision from the trial court is expected by the end of 2002.

Wyoming Tax Litigation RME filed tax appeals in March 1999 before the Wyoming Board of Equalization, alleging that the Wyoming Department of Revenue's revaluation of RME's crude oil production and natural gas production for the years 1989 through 1995 was erroneous. RME also filed a lawsuit in September 2000 in the First District Court of Laramie County, Wyoming, alleging that Wyoming's valuation statute was impermissibly vague. The Department of Revenue revalued RME's crude oil production based upon prices in Cushing, Oklahoma, as opposed to the price RME received at the wellhead from its marketing affiliate. The Department of Revenue also sought to revalue RME's natural gas production under a new valuation formula that was approved in a decision the Board of Equalization issued in other litigation while RME's dispute remained pending. RME argued that the price it received for its crude oil production reflected the actual market value of the oil at the wellhead, and that it was neither appropriate nor lawful to value crude oil in Wyoming according to transactions at Cushing. RME also argued that the formula the Department of

Revenue previously had used to value natural gas production for many years was the proper formula, and that the new formula approved by the Board of Equalization in the third-party litigation was erroneous. The amount in controversy was approximately $27 million. The Company settled the dispute for $10 million, of which RME already had paid $7 million under protest prior to the merger. As a result of the settlement, the parties have agreed to dismiss the tax appeals and the lawsuit.

CITGO Litigation CITGO Petroleum Corporation's (CITGO) claims arise out of an Asset Purchase and Contribution Agreement dated March 17, 1987 whereby RME's predecessor sold a refinery located in Corpus Christi, Texas to CITGO's predecessor. After the sale of the refinery, numerous individuals living near the refinery sued CITGO (the Neighborhood Litigation) thereby implicating the Asset Purchase and Contribution Agreement indemnity provision. CITGO and RME eventually entered into a settlement agreement to allocate, on an interim basis, each party's liability for defense and liability cost in that and related litigation. That agreement provides that once the Neighborhood Litigation and certain related claims are resolved, then the parties will determine their final indemnity obligations to each other through binding arbitration. At the present time, RME and CITGO have agreed to defer arbitrating the allocation of responsibility for this liability in order to focus their efforts on a global settlement. Arbitration will resume upon request of either CITGO or RME. In conjunction with this matter, RME sued Continental Insurance for denial of coverage for claims related to this dispute. RME and Continental Insurance settled the insurance coverage litigation which resulted in Continental Insurance paying RME for the claims. Negotiations and discussions with CITGO continue.

Kansas Ad Valorem Tax

General The Natural Gas Policy Act of 1978 allowed a "severance, production or similar" tax to be included as an add-on, over and above the maximum lawful price for natural gas. Based on the Federal Energy Regulatory Commission (FERC) ruling that the Kansas ad valorem tax was such a tax, the Company collected the Kansas ad valorem tax.

Background of PanEnergy Litigation FERC's ruling regarding the ability of producers to collect the Kansas ad valorem tax was appealed to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The Court held in June 1988 that FERC failed to provide a reasoned basis for its findings and remanded the case to FERC.

Ultimately, the D.C. Circuit issued a decision on August 2, 1996 ruling that producers must refund all Kansas ad valorem taxes collected relating to production since October 1983. The Company filed a petition for writ of certiorari with the Supreme Court. That petition was denied on May 12, 1997.

PanEnergy Litigation On May 13, 1997, the Company filed a lawsuit in the Federal District Court for the Southern District of Texas against PanEnergy seeking declaration that pursuant to prior agreements Anadarko is not required to issue refunds to PanEnergy for the principal amount of $14 million (before taxes) and, if the petition for adjustment is denied in its entirety by FERC with respect to PanEnergy refunds, interest in an amount of $38 million (before taxes). The Company also sought from PanEnergy the return of the $1 million (before taxes) charged against income in 1993 and 1994. In October 2000, the U.S. Magistrate issued recommendations concerning motions for summary judgment previously filed by both parties. In essence, the Magistrate's recommendation finds that the Company should be responsible for refunds attributable to the time period following August 1, 1985 while Duke Energy (as the successor company to Anadarko Production Company) should be responsible for refunds attributable to the time period before August 1, 1985.

The Company has reached a settlement agreement with PanEnergy that requires the Company to pay $15 million for settlement in full of all matters relating to the refunds of Kansas ad valorem tax reimbursements collected by the Company as first seller from August 1, 1985 through 1988. The settlement agreement was approved by the FERC and paid by Anadarko during 2001. The settlement agreement does not have any impact on the outstanding dispute between the Company and PanEnergy in connection with the refunds that relate to the Cimmaron River System. Anadarko's net income for 2001 included a $15 million charge (before taxes) related to the settlement agreement. Discussions with the Kansas Corporation Commission and PanEnergy to reach a settlement of the Cimmaron River System dispute are ongoing. At this time, it is estimated that a resolution may be reached in the first half of 2002, that may result in a payment by the Company of about $7 million. Accordingly, a provision for $7 million was charged against income in 2001.

Other Litigation Anadarko's net income for 1997 included a $2 million charge (before taxes) related to the Kansas ad valorem tax refunds. This charge reflects all principal and interest which may be due at the conclusion of all regulatory proceedings and litigation to parties other than PanEnergy. The Company is currently unable to predict the final outcome of this matter and no additional provision for liability has been made in the accompanying financial statements.

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 the Company, the liability with respect to these actions will not have a material effect on the Company.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders during the fourth quarter of 2001.

Executive Officers of the Registrant

Name	Age at End of 2002	Position
Robert J. Allison, Jr.	63	Chairman of the Board
John N. Seitz	51	President and Chief Executive Officer
Charles G. Manley	58	Executive Vice President, Administration
Michael E. Rose	55	Executive Vice President, Finance and Chief Financial Officer
William D. Sullivan	46	Executive Vice President, Exploration and Production
Rex Alman III	51	Senior Vice President, Domestic Operations
Michael D. Cochran	60	Senior Vice President, Strategy and Planning
Richard J. Sharples	55	Senior Vice President, Marketing and Minerals
Bruce H. Stover	53	Senior Vice President, Worldwide Business Development
Robert P. Daniels	43	Vice President, Canada
James J. Emme	46	Vice President, Exploration
Morris L. Helbach	57	Vice President, Information Technology Services and Chief Information Officer
James R. Larson	52	Vice President and Controller
Richard A. Lewis	58	Vice President, Human Resources
J. Stephen Martin	46	Vice President and General Counsel
J. Anthony Meyer	44	Vice President, Algeria
Mark L. Pease	46	Vice President, International and Alaska Operations
Gregory M. Pensabene	52	Vice President, Government Relations and Public Affairs
Albert L. Richey	53	Vice President and Treasurer
A. Paul Taylor, Jr.	53	Vice President, Investor Relations
Donald R. Willis	52	Vice President, Corporate Services

Mr. Allison relinquished the role of Chief Executive Officer in January 2002 and remains Chairman of the Board. He was named Chairman of the Board and Chief Executive Officer effective October 1986. He has worked for the Company since 1973.

Mr. Seitz was named President and Chief Executive Officer in January 2002. He was named President and Chief Operating Officer in 1999. He was named Executive Vice President, Exploration and Production and a member of the Company's Board of Directors during 1997. He has worked for the Company since 1977.

Mr. Manley was named Executive Vice President, Administration in 2000. Prior to this position, he served as Senior Vice President, Administration. He has worked for the Company since 1974.

Mr. Rose was named Executive Vice President, Finance and Chief Financial Officer in 2000. Prior to this position, he served as Senior Vice President, Finance and Chief Financial Officer. He has worked for the Company since 1978.

Mr. Sullivan was named Executive Vice President, Exploration and Production in 2001. He was named Vice President, Operations — International, Gulf of Mexico and Alaska in 2000. Prior to this position, he served as Vice President, International Operations. He has worked for the Company since 1981.

Mr. Alman was named Senior Vice President, Domestic Operations in 2001. Prior to this position, he served as Vice President, Domestic Operations. He has worked for the Company since 1976.

Dr. Cochran was named Senior Vice President, Strategy and Planning in 2001. Prior to this position he served as Vice President, Exploration. He has been with the Company since 1987.

Mr. Sharples was named Senior Vice President, Marketing and Minerals in 2001. Prior to this position, he served as Vice President, Marketing. He has been with the Company since 1993.

Mr. Stover was named Senior Vice President, Worldwide Business Development in 2001. Prior to this position, he served as Vice President, Worldwide Business Development since 1998 and Vice President, Acquisitions since 1993. He has worked for the Company since 1980.

Mr. Daniels was named Vice President, Canada in 2001. Prior to this position, he was Manager, Onshore Exploration. He has been with the Company since 1985.

Mr. Emme was named Vice President, Exploration in 2001. He was named Vice President, Canada in 2000. He has worked for the Company since 1981.

Mr. Helbach joined Anadarko in 2000 as Vice President, Information Technology Services and Chief Information Officer. Prior to joining Anadarko, he was General Manager and Chief Information Officer for Information Systems at Conoco, Inc.

Mr. Larson was named Vice President and Controller in 1995. He had served as the Company's Controller since 1986. He has worked for the Company since 1983.

Mr. Lewis was named Vice President, Human Resources in 1995. Prior to this position, he served as Manager of Employee Relations. He has worked for the Company since 1985.

Mr. Martin was named Vice President and General Counsel in 1995. He has worked for the Company since 1987.

Mr. Meyer was named Vice President, Algeria in 2001. Prior to this position, he served as President and General Manager, Anadarko Algeria Company LLC since 1998. He has worked for the Company since 1981.

Mr. Pease was named Vice President, International and Alaska Operations in September 2001. Prior to this position, he served as Vice President, Engineering and Technology since February 2001, Vice President, Algeria since 1998 and as President and General Manager, Anadarko Algeria Company LLC since 1993. He joined the Company in 1979.

Mr. Pensabene joined Anadarko in 1997 as Vice President, Government Relations. In 1999, Public Affairs was added to his responsibilities. Prior to joining Anadarko, he was a partner in various law firms in Washington, D.C.

Mr. Richey was named Vice President and Treasurer in 1995. He joined the Company as Treasurer in 1987.

Mr. Taylor was named Vice President, Investor Relations in 1999. Prior to this position, he served as Vice President, Corporate Communications. He has worked for the Company since 1986.

Mr. Willis was named Vice President, Corporate Services in 2000. Prior to this position, he served as Manager, Corporate Administration. He has worked for the Company since 1979.

All officers of Anadarko are elected in April of each year at an organizational meeting of the Board of Directors to 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.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

The common stock of Anadarko Petroleum Corporation is traded on the New York Stock Exchange. Average daily trading volume was 2,726,000 shares in 2001, 1,618,000 shares in 2000 and 672,000 shares in 1999. 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 closing market price of and dividends paid on the Company's common stock by quarter for 2001 and 2000.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2001				
Market Price				
High	**$72.99**	**$69.00**	**$59.75**	**$60.44**
Low	**$54.63**	**$53.40**	**$44.05**	**$47.45**
Dividends	**$ 0.05**	**$ 0.05**	**$ 0.05**	**$0.075**
2000				
Market Price				
High	$38.69	$53.25	$68.05	$74.85
Low	$28.44	$34.50	$44.44	$58.45
Dividends	$ 0.05	$ 0.05	$ 0.05	$ 0.05

As of December 31, 2001, there were approximately 26,000 direct holders of Anadarko common stock. The following table sets forth the amount of dividends paid on Anadarko common stock during the two years ended December 31, 2001.

millions	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2001	**$12**	**$13**	**$12**	**$20**
2000	$ 6	$ 6	$13	$13

The amount of future common stock dividends will depend on earnings, financial condition, capital requirements and other factors, and will be determined by the Directors on a quarterly basis.

For additional information, see *Dividends* under Item 7 and *Note 8 — Common Stock and Stock Options* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Item 6. Selected Financial Data

millions, except per share amounts	**2001**	% change 2001-2000	2000	1999	1998	1997
		Summary Financial Information*				
Revenues	**$ 8,369**	52	$ 5,500	$1,706	$ 1,307	$1,570
Operating Income (Loss)	**(318)**	n/m	1,419	175	(8)	203
Net Income (Loss) Available to Common Stockholders before Change in Accounting Principle	**(183)**	n/m	813	32	(49)	107
Net Income (Loss)	**(188)**	n/m	796	32	(49)	107
Net Cash Provided by Operating Activities	**$ 3,321**	116	$ 1,536	$ 318	$ 240	$ 362
Per Common Share:						
Net Income (Loss) — Basic	**$ (0.75)**	n/m	$ 4.32	$ 0.25	$ (0.41)	$ 0.90
Net Income (Loss) — Diluted	**$ (0.75)**	n/m	$ 4.16	$ 0.25	$ (0.41)	$ 0.89
Dividends	**$ 0.225**	13	$ 0.20	$ 0.20	$0.1875	$ 0.15
Average Shares Outstanding — Basic	**250**	36	184	125	120	119
Average Shares Outstanding — Diluted**	**250**	30	193	126	120	120
Capital Expenditures	**$ 3,316**	94	$ 1,708	$ 680	$ 917	$ 686
Long-term Debt	**$ 4,638**	16	$ 3,984	$1,443	$ 1,425	$ 956
Stockholders' Equity	**6,365**	(6)	6,786	1,535	1,259	1,117
Total Assets	**$16,771**	1	$16,590	$4,098	$ 3,633	$2,992
Annual Sales Volumes:						
Gas (Bcf)	**695**	81	385	170	177	179
Oil and Condensate (MMBbls)	**68**	89	36	15	11	9
NGLs (MMBbls)	**15**	25	12	7	7	5
Total Barrels of Oil Equivalent (MMBOE)	**199**	78	112	50	47	44
Average Daily Sales Volumes:						
Gas (MMcf/d)	**1,904**	81	1,052	465	484	490
Oil and Condensate (MBbls/d)	**186**	90	98	40	30	25
NGLs (MBbls/d)	**42**	27	33	18	18	15
Total Barrels of Oil Equivalent (MBOE/d)	**546**	78	306	135	129	121
Oil Reserves (MMBbls)	**1,132**	8	1,046	573	494	420
Gas Reserves (Tcf)	**7.0**	15	6.1	2.5	2.6	1.7
Total Reserves (MMBOE)	**2,305**	12	2,061	991	935	708
Worldwide Finding Cost ($/BOE)***	**$ 8.53**	19	$ 7.19	$ 4.87	$ 3.13	$ 4.28
Worldwide Reserve Replacement (% of Production)	**221%**	(79)	1,059%	213%	581%	341%
Number of Employees	**3,500**	—	3,500	1,400	1,500	1,400

Bcf — billion cubic feet
BOE — barrels of oil equivalent
MBbls/d — thousand barrels of oil per day
MBOE/d — thousand barrels of oil equivalent per day
MMBbls — million barrels
MMBOE — million barrels of oil equivalent
MMcf/d — million cubic feet per day
n/m — not meaningful
Tcf — trillion cubic feet

* Consolidated for Anadarko Petroleum Corporation and its principal subsidiaries, including RME Petroleum Company, RME Holding Company, Anadarko Canada Energy Ltd., Anadarko Canada Corporation, RME Land Corp. and Anadarko Algeria Company, LLC. Certain amounts for prior years have been reclassified to conform to the current presentation. See *Management's Discussion and Analysis of Financial Condition* and *Results of Operations* under Item 7 and *Consolidated Financial Statements and Notes* under Item 8 of this Form 10-K.

** For the years 2001 and 1998, 16 million and 1 million, respectively, potential common shares were not included in the computation of diluted shares since they had an anti-dilutive effect.

*** Worldwide finding costs are calculated by dividing worldwide costs incurred by the worldwide reserve additions, excluding sales in place.

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

Financial Results

Selected Financial Data

millions except per share amounts	**2001**	2000	1999
Revenues	**$8,369**	$5,500	$1,706
Costs and expenses	**8,687**	4,081	1,531
Merger expenses	**45**	67	—
Interest expense	**92**	93	74
Other (income) expense	**(65)**	(167)	(4)
Net income (loss) available to common stockholders before cumulative effect of change in accounting principle	**$ (183)**	$ 813	$ 32
Net income (loss) available to common stockholders	**$ (188)**	$ 796	$ 32
Earnings (loss) per share — before cumulative effect of change in accounting principle — basic	**$(0.73)**	$ 4.42	$ 0.25
Earnings (loss) per share — before cumulative effect of change in accounting principle — diluted	**$(0.73)**	$ 4.25	$ 0.25
Earnings (loss) per share — basic	**$(0.75)**	$ 4.32	$ 0.25
Earnings (loss) per share — diluted	**$(0.75)**	$ 4.16	$ 0.25

Net Income Anadarko's net loss available to common stockholders for 2001 totaled $188 million, or $0.75 per share (diluted), compared to net income available to common stockholders for 2000 of $796 million, or $4.16 per share (diluted). Net income for 2001 includes non-cash charges of $2.55 billion ($1.58 billion after taxes) for impairments of the carrying value of oil and gas properties primarily in the United States, Canada and Argentina as a result of low natural gas and oil prices at the end of the third quarter of 2001 as well as impairments related to exploration efforts in various international locations during 2001. See *Critical Accounting Policies*. Excluding the impairments, Anadarko had net income available to common stockholders of $1.39 billion, or $5.25 per share (diluted) for 2001. Net income for 2000 includes non-cash charges of $50 million ($32 million after taxes) for impairments related to exploration efforts in various international locations. Excluding the impairments, Anadarko had net income available to common stockholders in 2000 of $828 million or $4.32 per share (diluted). Anadarko's 1999 net income included a non-cash charge of $24 million ($15 million after taxes) related to impairments for exploration efforts in various international locations. Excluding the impairments, Anadarko had net income in 1999 of $47 million, or $0.37 per share (diluted). Anadarko's results include the effect of the merger with Union Pacific Resources Group Inc., subsequently renamed RME Holding Company (RME), which closed in July 2000, and the acquisition of Berkley Petroleum Corp. (Berkley), which closed in March 2001.

Revenues

millions	**2001**	2000	1999
Gas sales	**$2,893**	$1,591	$ 353
Oil and condensate sales	**1,380**	948	247
Natural gas liquids sales	**255**	264	88
Marketing sales	**3,776**	2,637	1,016
Minerals and other	**65**	60	2
Total	**$8,369**	$5,500	$1,706

Total revenues for 2001 increased $2.87 billion or 52% compared to 2000. Natural gas, crude oil and condensate and natural gas liquids (NGLs) revenues for 2001 increased $1.73 billion or 62% to $4.53 billion compared to $2.80 billion for 2000, due primarily to a significant increase in sales volumes, partially offset by a decrease in crude oil, condensate and NGLs prices. Marketing sales for 2001 increased $1.14 billion or 43% compared to 2000. The increase in marketing sales was due primarily to an increase in marketing sales volumes, which was partly offset by an increase in marketing purchases of $1.07 billion resulting primarily from higher oil and gas volumes purchased from third parties.

Anadarko's total revenues for 2000 were up $3.79 billion or 222% compared to total revenues in 1999. Natural gas, crude oil and condensate and NGLs revenues for 2000 increased $2.11 billion or 307% to $2.80 billion compared to $0.69 billion for 1999, due primarily to a significant increase in sales volumes and commodity prices. Marketing sales for 2000 increased $1.62 billion or 160% compared to 1999. The increase in marketing sales was due primarily to an increase in commodity prices, which was offset by an increase in marketing purchases of $1.67 billion resulting primarily from increased commodity prices for gas and oil volumes purchased from third parties.

Analysis of Oil and Gas Sales Volumes

	2001	2000	1999
Barrels of Oil Equivalent (MMBOE)			
United States	**144**	83	44
Canada	**34**	12	—
Algeria	**8**	10	6
Other International	**13**	7	—
Total	**199**	112	50

MMBOE — million barrels of oil equivalent

During 2001, Anadarko sold 199 MMBOE, an increase of 87 MMBOE or 78% compared to sales of 112 MMBOE in 2000. Approximately 70% of the increase in volumes during 2001 was due to a full year of operations in 2001 from properties acquired with the RME merger in July 2000, compared to 5½ months of operations in 2000. The remainder of the increase in volumes during 2001 was due primarily to increases of approximately 13 MMBOE from operations in the Gulf of Mexico, 7 MMBOE related to the acquisition of Berkley in March 2001, 6 MMBOE from operations in the Bossier play in Texas and Louisiana and 5 MMBOE from operations in Alaska. The Company's sales volumes were up 62 MMBOE or 124% in 2000 compared to 50 MMBOE in 1999. About 85% of the increase in volumes in 2000 was due to the merger with RME in mid-2000. The remainder of the increase in volumes during 2000 was due primarily to increases of 4 MMBOE from the Company's operations in Algeria. Sales volumes represent actual production volumes adjusted for changes in commodity inventories. Anadarko employs marketing strategies to help manage production and sales volumes and mitigate the effect of price volatility, which is likely to continue in the future. See *Derivative Financial Instruments* under Item 7a of this Form 10-K.

Natural Gas Sales Volumes and Average Prices

	2001	2000	1999
United States (Bcf)	**573**	338	170
MMcf/d	**1,569**	922	465
Price per Mcf before hedge	**$ 4.03**	$ 4.09	$2.08
Effect of hedge per Mcf	**0.12**	0.02	—
Price per Mcf	**$ 4.15**	$ 4.11	$2.08
Canada (Bcf)	**121**	46	—
MMcf/d	**331**	127	—
Price per Mcf before hedge	**$ 4.24**	$ 4.42	—
Effect of hedge per Mcf	**0.03**	(0.04)	—
Price per Mcf	**$ 4.27**	$ 4.38	—
Other International (Bcf)	**1**	1	—
MMcf/d	**4**	3	—
Price per Mcf	**$ 1.22**	$ 1.08	—
Total (Bcf)	**695**	385	170
MMcf/d	**1,904**	1,052	465
Price per Mcf before hedge	**$ 4.06**	$ 4.12	$2.08
Effect of hedge per Mcf	**0.10**	0.01	—
Price per Mcf	**$ 4.16**	$ 4.13	$2.08

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

The Company's natural gas sales volumes for 2001 were up 310 Bcf or 81% compared to 2000. Approximately 70% of the increase in natural gas volumes during 2001 was due to a full year of production in 2001 from properties acquired with the RME merger compared to 5½ months of production in 2000. The remainder of the increase in volumes during 2001 was due primarily to increases of approximately 44 Bcf from operations in the Gulf of Mexico, 34 Bcf from the Bossier play in Texas and Louisiana and 29 Bcf related to the acquisition of Berkley in March 2001. Anadarko's natural gas sales volumes in 2000 were up 215 Bcf or 126% compared to 1999. About 85% of the increase in natural gas volumes in 2000 was due to the merger with RME in July 2000. The remainder of the increase in volumes during 2000 was primarily due to increased production in the Bossier play in east Texas and Louisiana. Production of natural gas is generally not directly affected by seasonal swings in demand. However, the Company may decide during periods of low commodity prices to decrease development activity, which can result in decreased production volumes.

The Company's average wellhead gas price in 2001 was essentially flat compared to 2000. The higher natural gas prices realized in the first half of 2001 were offset by a decrease in natural gas prices in the second half of 2001. The decrease in prices during 2001 were attributed to a severe decline in natural gas demand as a result of high prices in early 2001, a national economic downturn and mild summer weather. The Company had less than 5% of its forecasted 2002 natural gas wellhead sales volumes hedged as of December 31, 2001. As a result, future natural gas revenues are subject to continued volatility based on fluctuations in market prices. Anadarko's average wellhead gas price in 2000 increased 99% from 1999. Natural gas markets improved significantly in 2000, with the Company's average realized price increasing from $2.08 per Mcf in 1999 to $4.13 per Mcf in 2000. The stronger prices were the result of lower nationwide production volumes and higher gas demand, particularly from electric power generation facilities.

Quarterly Natural Gas Sales Volumes and Average Prices

	2001	2000	1999
First Quarter			
Bcf	**164**	44	44
MMcf/d	**1,822**	486	489
Price per Mcf	**$ 6.79**	$ 2.46	$1.59
Second Quarter			
Bcf	**184**	49	42
MMcf/d	**2,018**	536	461
Price per Mcf	**$ 4.49**	$ 3.20	$1.95
Third Quarter			
Bcf	**176**	138	42
MMcf/d	**1,913**	1,498	456
Price per Mcf	**$ 2.89**	$ 3.83	$2.40
Fourth Quarter			
Bcf	**171**	154	42
MMcf/d	**1,863**	1,676	456
Price per Mcf	**$ 2.59**	$ 5.18	$2.40

Crude Oil and Condensate Sales Volumes and Average Prices

	2001	2000	1999
United States (MMBbls)	**34**	15	9
MBbls/d	**93**	40	23
Price per barrel before hedge	**$22.70**	$29.09	$15.87
Effect of hedge per barrel	**0.22**	(0.37)	(0.08)
Price per barrel	**$22.92**	$28.72	$15.79
Canada (MMBbls)	**13**	4	—
MBbls/d	**35**	12	—
Price per barrel before hedge	**$16.90**	$27.07	—
Effect of hedge per barrel	**0.43**	0.31	—
Price per barrel	**$17.33**	$27.38	—
Algeria (MMBbls)	**8**	10	6
MBbls/d	**22**	26	17
Price per barrel	**$23.97**	$28.76	$18.23
Other International (MMBbls)	**13**	7	—
MBbls/d	**36**	20	—
Price per barrel before hedge	**$14.35**	$18.46	—
Effect of hedge per barrel	**—**	(0.11)	—
Price per barrel	**$14.35**	$18.35	—
Total (MMBbls)	**68**	36	15
MBbls/d	**186**	98	40
Price per barrel before hedge	**$20.14**	$26.62	$16.87
Effect of hedge per barrel	**0.18**	(0.13)	(0.04)
Price per barrel	**$20.32**	$26.49	$16.83

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

Anadarko's crude oil and condensate sales volumes in 2001 increased 32 MMBbls or 89% compared to 2000. Approximately 65% of the increase in sales volumes during 2001 was due to a full year of operations in 2001 from properties acquired with the RME merger compared to 5½ months of operations in 2000. The remainder of the increase in crude oil and condensate sales volumes during 2001 was due primarily to increases of approximately 6 MMBbls from operations in the Gulf of Mexico, 5 MMBbls in Alaska and 2 MMBbls related to the acquisition of Berkley in March 2001. The 2000 oil and condensate volumes increased 21 MMBbls or 140% compared to 1999. About 85% of the increase in sales volumes in 2000 was due to the merger with RME in July 2000. The remainder of the increase in volumes during 2000 was due primarily to increases of 4 MMBbls from the Company's operations in Algeria. Production of oil usually is not affected by seasonal swings in demand or in market prices.

Anadarko's average realized crude oil prices for 2001 decreased 23% compared to 2000. The decrease in crude oil prices during 2001 is attributed primarily to a modest increase in supply and very slow growth in demand due to a worldwide economic downturn and a sharp decline in jet fuel consumption. The Company had less than 8% of its forecasted 2002 crude oil wellhead sales volumes hedged as of December 31, 2001. As a result, future oil and condensate revenues are subject to continued volatility based on fluctuations in market prices. Crude oil prices in 2000 were up 57% compared to 1999. The improvement in crude oil prices for 2000 was due in large part to a decrease in the production quotas among the Organization of Petroleum Exporting Countries (OPEC).

Quarterly Crude Oil and Condensate Sales Volumes and Average Prices

	2001	2000	1999
First Quarter			
MMBbls	**17**	4	4
MBbls/d	**186**	49	44
Price per barrel	**$21.59**	$26.28	$10.60
Second Quarter			
MMBbls	**18**	3	4
MBbls/d	**192**	38	42
Price per barrel	**$21.38**	$26.71	$14.97
Third Quarter			
MMBbls	**18**	13	3
MBbls/d	**192**	141	30
Price per barrel	**$21.66**	$27.68	$19.32
Fourth Quarter			
MMBbls	**16**	15	4
MBbls/d	**175**	161	44
Price per barrel	**$16.39**	$25.45	$23.02

Natural Gas Liquids Sales Volumes and Average Prices

	2001	2000	1999
Total (MMBbls)	**15**	12	7
MBbls/d	**42**	33	18
Price per barrel	**$16.51**	$21.70	$13.40

The Company's NGLs sales volumes in 2001 increased 25% compared to 2000. NGLs sales volumes in 2000 increased 71% compared to 1999. The 2001 average NGLs prices decreased 24% compared to 2000. By comparison, 2000 NGLs prices were 62% above 1999. NGLs production is dependent on natural gas prices and the economics of processing the natural gas volumes to extract NGLs.

Costs and Expenses

millions	**2001**	2000	1999
Marketing purchases	**$3,704**	$2,638	$ 972
Operating expenses	**716**	438	179
Administrative and general	**247**	180	102
Depreciation, depletion and amortization	**1,154**	593	218
Other taxes	**247**	128	36
Provisions for doubtful accounts	**—**	23	—
Impairments related to oil and gas properties	**2,546**	50	24
Amortization of goodwill	**73**	31	—
Total	**$8,687**	$4,081	$1,531

During 2001, Anadarko's costs and expenses increased $4.61 billion or 113% compared to 2000 due to the following factors:

— Marketing purchases increased $1.07 billion (40%) due primarily to an increase in oil and gas volumes purchased from third parties.

— Operating expenses increased $278 million (63%) primarily due to a significant increase in the number of producing wells as a result of the RME merger in mid-2000, the Berkley acquisition in early 2001 and significant development activity in the Gulf of Mexico, Alaska and the Bossier play in east Texas and Louisiana. Operating expenses were also impacted by an increase in oil field service costs.

— Administrative and general expenses increased $67 million (37%) primarily due to the Company's expanded workforce resulting from the RME merger in mid-2000 and higher costs associated with the Company's growing workforce.

— Depreciation, depletion and amortization (DD&A) expense increased $561 million (95%). About 80% of the increase was due to the increase in volumes as a result of the RME merger, the Berkley acquisition and significant development activity. The remaining increase is due to increases in the DD&A rate, which is also due to the RME merger and Berkley acquisition. As a result of the ceiling test impairments related to low oil and gas prices at the end of the third quarter of 2001, DD&A expense will be reduced in the future.

— Other taxes increased $119 million (93%). Approximately 50% of the increase was due to an increase in ad valorem taxes as a result of the significant increase in properties as a result of the merger and acquisitions. The remainder of the increase is primarily due to an increase in production taxes as a result of the increase in volumes.

— Impairments in 2001 were due to low oil and gas prices at the end of the third quarter of 2001, which resulted in ceiling test impairments for the United States ($1.70 billion), Canada ($808 million), Argentina ($15 million) and Brazil ($4 million), as well as unsuccessful exploration activities in the United Kingdom ($11 million) and Ghana ($7 million).

— Amortization of goodwill increased $42 million due to the RME merger in mid-2000 ($32 million) and the Berkley acquisition in 2001 ($10 million).

During 2000, Anadarko's costs and expenses increased $2.55 billion or 167% compared to 1999 due to the following factors:

— Marketing purchases increased $1.67 billion (171%) due primarily to an increase in commodity prices for gas and oil volumes purchased from third parties.

— Operating expenses increased $259 million (145%) due primarily to the significant increase in number of producing wells as a result of the RME merger and higher downstream expenses associated with an increase in NGLs production.

— Administrative and general expenses were up $78 million (76%) due primarily to an increase in costs associated with the Company's growing workforce as a result of the RME merger in mid-2000.

— DD&A expense increased $375 million (172%). About 76% of the increase was due to a 124% increase in volumes as a result of the RME merger and higher volumes in Algeria and the Bossier play in east Texas and Louisiana. The remaining increase is due primarily to an increase in the DD&A rate as a result of the RME merger.

- Other taxes increased $92 million (256%). Approximately 75% of the increase was due to an increase in production taxes as a result of higher volumes associated with the RME merger and an increase in commodity prices in 2000. The remainder of the increase was due to higher ad valorem taxes as a result of the significant increase in properties and higher payroll taxes as a result of the increase in employees as a result of the RME merger.
- Provisions for doubtful accounts increased $23 million due to default by one creditor.
- Impairments in 2000 related to unsuccessful exploration activities in the United Kingdom ($17 million), Tunisia ($13 million), Ireland ($10 million) and other international locations ($10 million).
- Amortization of goodwill was $31 million due to the RME merger in mid-2000.

Merger Expenses

During 2001 and 2000, merger costs of $41 million and $67 million, respectively, were expensed related to the RME merger. These costs relate primarily to the issuance of stock for retention of employees, deferred compensation, transition, integration, hiring and relocation costs, vesting of restricted stock and stock options and retention bonuses. For 2001, merger costs of $4 million were expensed related to the Berkley and Gulfstream Resources Canada Limited (Gulfstream) acquisitions. There were no merger related expenses in 1999. Any additional expenses related to the RME, Berkley or Gulfstream acquisitions are expected to be minimal and will be included in administrative and general expenses in the future.

Interest Expense

millions	**2001**	2000	1999
Gross interest expense	**$ 301**	$ 193	$ 96
Capitalized interest	**(209)**	(100)	(22)
Net interest expense	**$ 92**	$ 93	$ 74

Anadarko's gross interest expense has increased over the past three years due primarily to the RME merger in mid-2000 and the Berkley acquisition in 2001 as well as higher levels of borrowings for capital expenditures, including producing property acquisitions. Gross interest expense in 2001 increased 56% compared to 2000 primarily due to the RME merger in mid-2000 and the Berkley acquisition in 2001 which resulted in higher average borrowings during 2001. Gross interest expense in 2000 was up 101% compared to 1999 primarily due to the RME merger and higher average borrowings in 2000. See *Capital Resources and Liquidity* and *Outlook on Liquidity*.

In 2001, capitalized interest increased by 109% compared to 2000 primarily due to an increase in costs excluded from the DD&A pools related to the RME merger in mid-2000 and the Berkley acquisition in 2001. In 2000, capitalized interest increased by 355% compared to 1999 primarily due to an increase in costs excluded related to the RME merger. For additional information about the Company's policies regarding costs excluded and capitalized interest see *Critical Accounting Policies — Costs Excluded* and *Capitalized Interest.*

Other (Income) Expense

millions	**2001**	2000	1999
Firm transportation keep-whole contract valuation	**$(91)**	$(175)	$—
Foreign currency exchange	**29**	7	—
Change in time value options	**(18)**	—	—
Other	**15**	1	(4)
Total	**$(65)**	$(167)	$(4)

Other income in 2001 decreased $102 million or 61% compared to the same period of 2000 due primarily to an $84 million decrease related to the effect of significantly lower market value for firm transportation subject to a keep-whole agreement and a $22 million increase in foreign currency exchange losses primarily due to changes in the Canadian exchange rates. Other income for 2000 includes $175 million related to the effect of significantly higher market values for firm transportation subject to a keep-whole agreement. The keep-whole agreement was acquired with the RME merger in 2000. See *Derivative Financial Instruments* and *Foreign Currency Risk* under Item 7a of this Form 10-K.

Marketing Strategies

Overview The Company's sales of natural gas, crude oil, condensate and NGLs are generally made at the market prices of those products at the time of sale. Therefore, even though the Company has several large purchasers, the Company believes other purchasers would be willing to buy the Company's natural gas, crude oil, condensate and NGLs at comparable market prices. The Company's marketing department actively manages sales of its oil and gas through Anadarko Energy Services Company (AES), Anadarko, Anadarko Canada Corporation and RME. The Company also conducts trading activities for the purpose of generating profits on or from exposure to changes in the market prices of gas, crude oil, condensate and NGLs. However, the Company does not engage in market-making practices nor does it trade in any non-energy-related commodities. The Company's trading risk position, most of the time, is a net short position that is offset by the Company's natural long position as a producer. Essentially all of the Company's trading transactions have a term of less than one year and most are less than three months. See *Derivative Financial Instruments* under Item 7a of this Form 10-K.

Natural Gas The North American natural gas market has grown significantly throughout the last 10 years and management believes continued growth to be likely. Natural gas prices have been extremely volatile and are expected to continue to be so. Management believes the Company's excellent portfolio of exploration and development prospects should position Anadarko to continue to participate in this growth. Anadarko's wholly-owned marketing subsidiary — AES — is a full-service marketing company offering supply assurance, competitive pricing and services tailored to its customers' needs. Approximately 36% of the Company's gas production was sold through AES in 2001. AES also purchases and sells third-party produced gas in the Company's market areas. Third-party purchases allow the Company to aggregate larger volumes of gas and attract larger, more creditworthy customers, which in turn spreads the Company's relatively fixed overhead costs over more gas and can help to reduce transportation costs. AES sells natural gas under a variety of contracts and may also receive a service fee related to the level of reliability and service required by the customer. AES has the marketing capability to move large volumes of gas into and out of the "daily" gas market to take advantage of any price volatility. Included in this strategy is the use of leased natural gas storage facilities and various derivative financial instruments. The Company also conducts trading activities for the purpose of generating profits on or from exposure to changes in the market price of natural gas.

RME was a party to several long-term firm gas transportation agreements that supported the gas marketing program within the gathering, processing and marketing (GPM) business segment, which was sold in 1999 to Duke Energy Field Services, Inc. (Duke). Most of the GPM's firm long-term transportation contracts were transferred to Duke in the GPM disposition. One contract was retained, but is managed and operated by Duke. Anadarko is not responsible for the operations of the contracts and does not utilize the associated transportation assets to transport the Company's natural gas. As part of the GPM disposition, RME and Duke signed a keep-whole agreement, under which RME will pay Duke if the transportation market values fall below the fixed contract transportation rates, while Duke will pay RME if the transportation market values exceed the contract transportation rates (keep-whole agreement). The fair value of the short-term portion of the firm transportation keep-whole agreement is calculated with actively quoted natural gas basis prices. Basis is the difference in value between gas at various delivery points and the NYMEX gas futures contract price. Management believes that natural gas basis price quotes beyond the next twelve months are not reliable indicators of fair value due to decreasing liquidity. Accordingly, the fair value of the long-term portion is estimated based on historical natural gas basis prices, discounted at a 10% per year. Management also periodically evaluates the supply and demand factors (such as expected drilling activity, anticipated pipeline construction projects, expected changes in demand at pipeline delivery points) that may impact the future market value of the firm transportation capacity to determine if the estimated fair value should be adjusted.

In 2001 and 2000, approximately 31% and 56%, respectively, of the Company's gas production was sold under long-term contracts to Duke Energy. These sales represent 17% and 18%, respectively, of total revenues in 2001 and 2000. Most of the Company's gas production sold to Duke Energy is under a single agreement that expires at the end of the first quarter of 2004. Volumes sold to Duke under this contract may be delivered at a number of locations generally at the tailgate of processing facilities owned or operated by Duke Energy or its affiliates and typically in the general vicinity of the fields where produced. The pricing of gas under this contract is market based and therefore varies monthly and by region.

Crude Oil, Condensate and NGLs Anadarko's crude oil, condensate and NGLs revenues are derived from production in the U.S., Canada, Algeria and other international areas. Most of the Company's U.S. crude oil and NGLs production is on 30-day "evergreen" contracts with prices based on marketing indices and adjusted for location, quality and transportation. Most of the Company's Canadian oil production is sold on a term basis of one year or greater. Oil from Algeria is sold by tanker as Saharan Blend to customers primarily in the Mediterranean area. Saharan Blend is a high quality crude that provides refiners with large quantities of premium products like high quality jet and diesel fuel. AES purchases and sells third-party crude oil, condensate and NGLs in the Company's domestic and international market areas. Included in this strategy is the use of leased crude oil storage facilities and various derivative financial instruments.

Gas Gathering Systems and Processing Anadarko's investment in gas gathering operations allows the Company to better manage its gas production, improve ultimate recovery of reserves, enhance the value of gas production and expand marketing opportunities. The Company has invested $173 million to build or acquire gas gathering systems over the last five years. The vast majority of the gas flowing through these systems is from Anadarko operated wells.

The Company processes gas at various third-party plants under agreements generally structured to provide for the extraction and sale of NGLs in efficient plants with flexible commitments. Anadarko also processes gas and has interests in one operated plant and three non-operated plants. Anadarko's strategy to aggregate gas through Company-owned and third-party gathering systems allows Anadarko to secure processing arrangements in each of the regions where the Company has significant production.

Anadarko purchased Pinnacle Gas Treating, Inc., for $38 million, in January 2001. The purchase gives Anadarko ownership of a natural gas gathering system that runs through the heart of its Bossier properties. The acquisition provides the Company greater flexibility in shipping and marketing its gas from the area as well as improved service to other shippers. The network, which has a capacity of 500 MMcf/d of gas, consists of 60 miles of large-diameter pipe, 40 miles of small-diameter laterals and spurs in addition to a 60-mile fuel redelivery system. In 2001, Anadarko expanded the Bethel plant acquired in the transaction to accommodate growing volumes in the area. The Bethel treating plant removes carbon dioxide and hydrogen sulfide from gas and can handle as much as 500 MMcf/d of gas.

Marketing Contracts The following schedules provide additional information regarding the Company's marketing and trading portfolio of physical and derivative contracts and the firm transportation keep-whole agreement as of December 31, 2001. The Company records income on these activities using the mark-to-market method. See *Critical Accounting Policies* for an explanation of how the fair value for derivatives are calculated. In 2001, the use of mark-to-market accounting compared to historical cost accounting resulted in additional non-cash income of $31 million, before taxes, related to the marketing and trading activities and reduced non-cash income related to the firm transportation keep-whole agreement by $74 million, before taxes.

millions	**Marketing and Trading**	**Firm Transportation Keep-whole**	**Total**
Fair value of contracts outstanding at December 31, 2000	$(12)	$ 40	$ 28
Contracts realized or otherwise settled during 2001	(22)	(213)	(235)
Fair value of new contracts when entered into during 2001	10	—	10
Other changes in fair value	41	91	132
Fair value of contracts outstanding at December 31, 2001	$ 17	$ (82)	$ (65)

Assets (Liabilities) *millions*	Maturity less than 1 year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	Total
	Fair Value of Contracts at December 31, 2001				
Marketing and Trading					
Prices actively quoted	$15	$ 1	$ —	$ —	$ 16
Prices based on models and other valuation methods	1	—	—	—	1
Firm Transportation Keep-whole					
Prices actively quoted	$(2)	$ —	$ —	$ —	$ (2)
Prices based on models and other valuation methods	—	(40)	(27)	(13)	(80)
Total					
Prices actively quoted	$13	$ 1	$ —	$ —	$ 14
Prices based on models and other valuation methods	1	(40)	(27)	(13)	(79)

Operating Results

Drilling Activity During 2001, Anadarko participated in a total of 1,420 gross wells, including 970 gas wells, 375 oil wells and 75 dry holes. This compares to 709 gross wells (385 gas wells, 269 oil wells and 55 dry holes) in 2000 and 200 gross wells (122 gas wells, 52 oil wells and 26 dry holes) in 1999. The increase in activity during 2001 was a result of the RME merger, the Berkley acquisition and improved commodity prices at the beginning of the year.

The Company's 2001 exploration and development drilling program is discussed in *Oil and Gas Properties and Activities* under Item 1 of this Form 10-K.

Drilling Program Activity

	Gas	Oil	Dry	Total
2001 Exploratory				
Gross	**47**	**35**	**40**	**122**
Net	**35.6**	**26.0**	**27.0**	**88.6**
2001 Development				
Gross	**923**	**340**	**35**	**1,298**
Net	**677.5**	**262.5**	**26.6**	**966.6**
2000 Exploratory				
Gross	17	15	24	56
Net	11.7	10.1	17.6	39.4
2000 Development				
Gross	368	254	31	653
Net	300.3	196.0	24.8	521.1

Gross: total wells in which there was participation.
Net: working interest ownership.

Reserve Replacement Drilling activity is not the best measure of success for an exploration and production company. Anadarko focuses on growth and profitability. Reserve replacement is the key to growth and future profitability depends on the cost of finding oil and gas reserves, among other factors. The Company believes its performance in both areas is excellent. For the 20th consecutive year, Anadarko more than replaced annual production volumes with proved reserves of natural gas, crude oil, condensate and NGLs, stated on a barrel of oil equivalent (BOE) basis.

During 2001, Anadarko's worldwide reserve replacement was 221% of total production — which reached a record of 201 MMBOE. The Company's worldwide reserve replacement in 2000 was 1,059% of total production of 112 MMBOE. The Company's worldwide reserve replacement in 1999 was 213% of total production of 50 MMBOE. Over the last five years, the Company's annual reserve replacement has averaged 476% of annual production volumes.

Excluding mergers, acquisitions and divestitures, Anadarko's worldwide reserve replacement for 2001 was 173% of total production compared to 231% for 2000 and 236% for 1999. Excluding mergers, acquisitions and divestitures, the Company's annual worldwide reserve replacement over the past five years averaged 243% of annual production volumes.

Anadarko continues to increase its energy reserves in the U.S. In 2001, the Company replaced 161% of its U.S. production volumes with U.S. reserves. This compares to a U.S. reserve replacement of 855% in 2000 and 128% in 1999. The Company's U.S. reserve replacement for the five-year period 1997-2001 was 360% of production. Excluding mergers, acquisitions and divestitures, Anadarko's U.S. reserve replacement for 2001, 2000 and 1999 was 160%, 207% and 101%, respectively, of total production. The Company's U.S. reserve replacement for the five-year period 1997-2001 was 195% excluding mergers, acquisitions and divestitures. By comparison, the most recent published U.S. industry average (1996-2000) was 109%. (Source: U.S. Department of Energy) Anadarko's U.S. reserve replacement performance for the same period 1996-2000 was 452% of production or 218% of production, excluding mergers, acquisitions and divestitures. Industry data for 2001 are not yet available.

Cost of Finding Cost of finding results in any one year can be misleading due to the long lead times associated with exploration and development. A better measure of cost of finding performance is over a five-year period. Anadarko has historically outperformed the industry in average finding costs. For the period 1997-2001, Anadarko's worldwide finding cost was $6.66 per BOE. The Company's U.S. finding cost for the same five-year period was $7.58 per BOE. Excluding mergers and acquisitions, Anadarko's worldwide and U.S. finding costs for the five-year period 1997-2001 were $5.88 per BOE and $6.78 per BOE, respectively. Industry data for 2001 are not yet available. For comparison purposes, the most recently published five-year average (1996-2000) for the industry shows worldwide finding cost was $4.32 per BOE and U.S. finding cost was $5.63 per BOE. (Source: Arthur Andersen) For the same five-year period of 1996-2000, Anadarko's worldwide finding cost was $5.89 per BOE and its U.S. finding cost was $6.86 per BOE. For the five-year period 1996-2000, the Company's worldwide and U.S. finding costs excluding mergers and acquisitions were $4.30 per BOE and $5.15 per BOE, respectively.

For 2001, Anadarko's worldwide finding cost was $8.53 per BOE. This compares to $7.19 per BOE in 2000 and $4.87 per BOE in 1999. Anadarko's U.S. finding cost for 2001 was $9.60 per BOE. This compares to $8.49 per BOE in 2000 and $9.06 per BOE in 1999. Excluding mergers and acquisitions, Anadarko's worldwide finding costs for 2001 was $8.75 per BOE compared to $5.83 per BOE in 2000 and $5.17 per BOE in 1999. The Company's U.S. finding costs excluding mergers and acquisitions for 2001 was $9.46 per BOE compared to $6.77 per BOE in 2000 and $11.52 per BOE in 1999. Finding costs in 2001 have increased due primarily to increases in oilfield services costs and increased exploration and development activity.

Proved Reserves At the end of 2001, Anadarko's proved reserves were 2.3 billion BOE compared to 2.1 billion BOE at year-end 2000 and 991 MMBOE at year-end 1999. Reserves increased 12% in 2001 compared to 2000 due primarily to exploration and development drilling in both the U.S. and overseas and the Berkley and Gulfstream acquisitions. Anadarko's proved reserves have grown 147% over the past three years, primarily as a result of the RME merger in 2000, the Berkley and Gulfstream acquisitions in 2001, successful exploration projects in Alaska, Algeria and the Gulf of Mexico, and successful development drilling programs in major domestic fields in core areas onshore and offshore.

The Company's proved natural gas reserves at year-end 2001 were 7.04 trillion cubic feet (Tcf) compared to 6.09 Tcf at year-end 2000 and 2.51 Tcf at year-end 1999. Anadarko's proved gas reserves have increased 166% since year-end 1998, reflecting the RME merger in 2000 and the Berkley and Gulfstream acquisitions in 2001, continued development activity onshore in the U.S. and other producing property acquisitions. Anadarko's crude oil, condensate and NGLs reserves at year-end 2001 increased 8% to 1.13 billion barrels compared to 1.05 billion barrels at year-end 2000 and 573 MMBbls at year-end 1999. Crude oil reserves have risen by 129% over the last three years primarily due to the RME merger in 2000, the Berkley and Gulfstream acquisitions in 2001 and large discoveries in Alaska, Algeria and the Gulf of Mexico. Crude oil, condensate and NGLs reserves comprise 49% of the Company's proved reserves at year-end 2001 compared to 51% at year-end 2000 and 58% at year-end 1999.

At December 31, 2001, the present value (discounted at 10%) of future net revenues from Anadarko's proved reserves was $11.5 billion, before income taxes, and was $8.0 billion, after income taxes, (stated in accordance with the regulations of the Securities and Exchange Commission (SEC) and the Financial Accounting Standards Board (FASB)). This present value was calculated based on prices at year-end held flat for the life of the reserves, adjusted for any contractual provisions. The after income taxes decrease of $13.4 billion or 62% in 2001 compared to 2000 is primarily due to significantly lower natural gas and crude oil prices at year-end 2001, partially offset by additions of proved reserves related to successful drilling worldwide and the Berkley and Gulfstream acquisitions. See *Critical Accounting Policies* under Item 7 and *Supplemental Information on Oil and Gas Exploration and Production Activities — Unaudited* in the Consolidated Financial Statements under Item 8 of this Form 10-K.

The present value of future net revenues does not purport to be an estimate of the fair market 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 gas.

Acquisitions and Divestitures

The Company's strategy includes an active asset acquisition and divestiture program. In 2001, the Company acquired approximately 157 MMBOE of proved reserves, located in: Canada, primarily from the Berkley acquisition (99 MMBOE), Qatar and Oman with the Gulfstream acquisition (57 MMBOE) and the United States (1 MMBOE). In 2000, Anadarko acquired with the RME merger approximately 912 MMBOE of proved reserves, located primarily in the United States, Canada and Latin America. Excluding the RME, Berkley and Gulfstream acquisition transactions, during 1999-2001, Anadarko acquired through purchases and trades 33 MMBOE of proved reserves for $118 million. During the same time period, the Company sold properties, either as a strategic exit from a certain area or asset rationalization in existing core areas, with proceeds totaling $289 million. Reserves associated with these sales and trades were 90 MMBOE. In 2002, the Company will continue to consider dispositions of certain producing properties in non-core areas.

Properties and Leases

Producing Properties The Company owns 9,493 net producing gas wells and 6,321 net producing oil wells worldwide. The following schedule shows the number of developed and undeveloped lease acres in which Anadarko held interests at December 31, 2001.

Acreage

	Developed		Undeveloped		Total	
thousands	Gross	Net	Gross	Net	Gross	Net
United States						
Onshore — Lower 48	2,714	1,901	2,322	1,583	5,036	3,484
Offshore	483	220	1,251	892	1,734	1,112
Alaska	32	7	1,400	481	1,432	488
Total	3,229	2,128	4,973	2,956	8,202	5,084
Canada	1,942	1,118	9,102	3,554	11,044	4,672
Algeria*	209	50	3,387	1,176	3,596	1,226
Other International	427	87	29,981	15,314	30,408	15,401

* Developed acreage in Algeria relates only to areas with an Exploitation License. A portion of the undeveloped acreage in Algeria will be relinquished in the future upon finalization of Exploitation License boundaries.

Land Grant and Other Fee Minerals The Company also owns fee mineral interests on acreage totaling 10,138,000 (gross) or 9,109,000 (net) acres as of December 31, 2001. Of this amount, 7,929,000 (gross) or 7,740,000 (net) acres are within the Company's Land Grant area in Wyoming, Colorado and Utah, which was granted by the federal government to a predecessor of RME in the mid-1800s. The Company holds royalty interests of varying percentages in approximately one million gross acres of the Land Grant that are subject to exploration and production agreements with third-parties. The Company's fee mineral acreage is primarily undeveloped.

Capital Resources and Liquidity

Capital Expenditures*

millions	**2001**	2000	1999
Development	**$1,641**	$ 921	$311
Exploration	**1,030**	429	189
Acquisitions of producing properties	**14**	54	50
Gathering and other	**244**	80	27
Capitalized interest and exploration and development costs	**387**	224	103
Total	**$3,316**	$1,708	$680

* Excludes corporate acquisitions

The Company's primary focus for 2001 was to develop existing fields and find additional reserves in the Lower 48 states, the Gulf of Mexico and in Canada. Anadarko's total capital spending in 2001 was $3.3 billion, a 94% increase compared to 2000. The increase from 2000 represents a $720 million increase in development spending, a $601 million increase in exploration spending and a $287 million increase in spending primarily for general properties and capitalized interest. The development spending increase was primarily in the Lower 48 states, while the exploration spending increase was primarily in the Gulf of Mexico and the Lower 48 states.

Anadarko's total capital spending for 2000 was $1.7 billion, a 151% increase compared to 1999. The increase from 1999 represents a $610 million increase in development spending, a $240 million increase in exploration spending and a $178 million increase in spending for capitalized interest and other costs. The increase in development spending was primarily related to the United States and Canada as a result of the RME merger, as well as an increase in Algeria's construction development spending.

The Company funded its capital investment programs in 2001, 2000 and 1999 primarily through cash flow, plus increases in long-term debt, issuances of common stock and proceeds from property sales.

Capital spending for 2002 has been initially set at $2.0 billion, which is a 40% decrease compared to 2001. The primary focus of the 2002 budget is to find additional oil and gas reserves and maintain Company-wide production at current levels. Anadarko has allocated nearly $1.0 billion to worldwide development projects, primarily for fields in the Gulf of Mexico, western Canada, east and central Texas, north Louisiana, the western states and Algeria. Approximately $500 million is budgeted for exploration programs, mainly in the Gulf of Mexico, east Texas, north Louisiana, Alaska, western Canada, Congo and Australia. About 70% of the exploration budget will be for drilling. The remainder of the exploration budget will be used for seismic and lease acquisitions. See *Outlook on Liquidity* for a discussion of the sources of funds for capital spending.

Debt At year-end 2001, Anadarko's total debt was $5.1 billion. This compares to total debt of $4.0 billion at year-end 2000 and $1.4 billion at year-end 1999. As a result of the RME merger, the liabilities of RME became liabilities of the Company. The increases in debt are related primarily to the RME merger in 2000 and the Berkley and Gulfstream acquisitions in 2001.

In March 2001, Anadarko issued $650 million of Zero Yield Puttable Contingent Debt Securities (ZYP-CODES) due 2021 to qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S. The debt securities were priced with a zero coupon, zero yield to maturity and a conversion premium of 38%. The proceeds from the debt securities were used initially to finance costs associated with the acquisition of Berkley. Holders of the ZYP-CODES have the right to require Anadarko to purchase all or a portion of their ZYP-CODES in March 2002, 2004, 2006, 2011 or 2016, at $1,000 per ZYP-CODES. In March 2002, ZYP-CODES in the amount of $620 million were put to the Company for repayment and were paid in cash.

In April 2001, Anadarko Finance Company, a wholly-owned finance subsidiary of Anadarko, issued $1.3 billion in notes as part of the Company's financial restructuring plan. This issuance was made up of $400 million of 6¾% Notes due 2011 and $900 million of 7½% Notes due 2031. In May 2001, Anadarko Finance Company issued an additional $550 million of 6¾% Notes due 2011, bringing the 6¾% Notes to an aggregate total of $950 million. The notes are fully and unconditionally guaranteed by Anadarko. The notes were issued as part of an exchange of securities for other Anadarko debt.

In October 2001, the Company entered into a Revolving Credit Agreement and a 364-Day Revolving Credit Agreement. Each agreement provides for a $225 million principal amount and expires in 2004 and 2002, respectively. In October 2001, Anadarko Canada Corporation, a wholly-owned subsidiary of Anadarko, entered into a 364-Day Canadian Credit Agreement. The agreement provides for a US$300 million principal amount and expires in 2002. The agreement is fully and unconditionally guaranteed by Anadarko. As of December 31, 2001, the Company had $69 million outstanding under the Canadian Credit Agreement.

In February 2002, the Company issued $650 million principal amount of 5⅜% Notes due March 2007. In March 2002, the Company issued $400 million principal amount of 6⅛% Notes due March 2012. The net proceeds from these issuances were used to reduce floating-rate debt and to fund a portion of the ZYP-CODES put to the Company for repayment in March 2002.

Preferred Stock During 2001, Anadarko repurchased $97 million of preferred stock. The resulting gain of $13 million was recorded to paid-in capital.

Common Stock Purchase Program In July 2001, the Board of Directors authorized the Company to purchase up to $1 billion in shares of Anadarko common stock. The share purchases may be made from time to time, depending on market conditions. Shares may be purchased either in the open market or through privately negotiated transactions. The repurchase program does not obligate Anadarko to acquire any specific number of shares and may be discontinued at any time.

To enhance the share repurchase program, Anadarko has sold put options to independent third parties. These put options entitle the holder to sell shares of Anadarko common stock to the Company on certain dates at specified prices. During 2001, Anadarko sold put options for the purchase of a total of 5 million shares of Anadarko common stock with a notional amount of $240 million. Put options for 1 million shares were exercised and put options for 2 million shares expired unexercised in 2001. During 2001, premiums of $15 million were received related to these put options and recorded as an increase to paid-in capital. In January 2002, the Company entered into additional put options for 1 million shares of Anadarko common stock with a notional amount of $46 million and received a $3 million premium. Put options for an additional 1 million shares expired unexercised in 2002. The remaining put options for 2 million shares will expire in March and July 2002, if not exercised. The put options permit a net-share settlement at the Company's option and do not result in a liability on the consolidated balance sheet as of December 31, 2001.

The following table summarizes purchases under the stock purchase program and the effect of the related put option premiums on the repurchase price.

million, except per share amounts	Third Quarter 2001	Fourth Quarter 2001	Annual 2001	Year to Date March 15, 2002	Total Program
Shares repurchased	2.2	—	2.2	1.0	3.2
Total paid for shares repurchased	$ 116	$ —	$ 116	$ 50	$ 166
Put premiums settled	(5)	(2)	(7)	(4)	(11)
Total repurchase price	$ 111	$ (2)	$ 109	$ 46	$ 155
Average repurchase price per share	$50.41	n/m	$49.41	$46.25	$48.42

Obligations and Commitments

Following is a summary of the Company's future payments on obligations as of December 31, 2001.

	Obligations by Period				
millions	1 Year	2-3 Years	4-5 Years	Later Years	Total
Total debt*	$708	$1,003	$432	$3,052	$5,195
Operating leases	72	135	105	263	575
Transportation and storage	23	37	19	100	179
Oil and gas activities	—	112	51	—	163

* Includes convertible debt that can be put back to the Company including: $620 million in 2002 and $30 million in 2004 related to the ZYP-CODES; and, $367 million in 2003 related to the Zero Coupon Convertible Debentures.

Synthetic Leases In November 1999, Anadarko entered into a build-to-suit lease arrangement for its corporate office building in The Woodlands, Texas. The development and acquisition of the property was financed by a special purpose entity (SPE) sponsored by a financial institution. The lease balance to be funded under this arrangement will not exceed $185 million. The SPE is not consolidated in the Company's financial statements and, based on the initial terms of the agreement, the Company has accounted for this arrangement as an operating lease in accordance with Statement of Financial Accounting Standard (SFAS) No. 13, "Accounting for Leases."

The initial lease term is five years, with up to seven one-year renewal options. Monthly lease payments are based on the London interbank borrowing rate applied against the lease balance and are expected to begin in 2002. Future minimum lease payments under this lease are included in the table above. The lease contains various covenants including covenants regarding the Company's financial condition. Default under the lease, including violation of these covenants, could require the Company to purchase the facility for a specified amount, which approximates the lessor's original cost ($123 million funded as of December 31, 2001). As of December 31, 2001, the Company was in compliance with these covenants.

At the end of the lease term, the Company has an option to either purchase the facility for the purchase option amount of the lease balance plus any outstanding lease payments or to assist the SPE in the sale of the property. The Company has provided a residual value guarantee for any deficiency if the property is sold for less than the sale option amount ($104 million at December 31, 2001). In addition, the Company is entitled to any proceeds from a sale of the property in excess of the purchase option amount.

In December 2000, the Company entered into a lease arrangement for an office building in The Woodlands, Texas. The acquisition of the property was financed by an SPE sponsored by a financial institution. The amount funded was $48 million. The SPE is not consolidated in the Company's financial statements and the Company has accounted for this arrangement as an operating lease in accordance with SFAS No. 13.

The initial lease term is five years. Monthly lease payments, which began in 2001, are based on the London interbank borrowing rate applied against the $48 million lease balance. Future minimum lease payments under this lease are included in the table above. The lease contains various covenants including covenants regarding the Company's financial condition. Default under the lease, including violation of these covenants, could require the Company to purchase the facility for a specified amount, which approximates the lessor's original cost ($48 million). As of December 31, 2001, the Company is in compliance with these covenants.

At the end of the lease term, the Company has an option to either purchase the facility for the purchase option amount of $48 million plus any outstanding lease payments or to assist the SPE in the sale of the property. The Company has provided a residual value guarantee for any deficiency if the property is sold for less than the sale option amount ($39 million at December 31, 2001). In addition, the Company is entitled to any proceeds from a sale of the property in excess of the purchase option amount.

If, for either of these leases, the Company determines that it is probable that the expected fair value of the property at the end of the lease term will be less than the purchase option amount, the Company will accrue the expected loss on a straight line basis over the remaining lease term. Currently, management does not believe it is probable that the fair market value of either of these properties will be less than the purchase option amount at the end of the lease term.

Oil and Gas Activities As is common in the oil and gas industry, Anadarko has various contractual commitments pertaining to exploration, development and production activities. The amounts in the table reflect obligations and commitments that are not included in the 2002 capital budget. Following is a description of the Company's significant operating obligations and commitments related to oil and gas activities.

Production Platform In December 2001, the Company signed a letter of intent with El Paso Energy Partners (EPN) under which a floating production platform for its Marco Polo discovery in Green Canyon Block 608 of the Gulf of Mexico will be installed. EPN will construct the platform and processing facilities that upon completion, expected in 2004, will be operated by Anadarko. The proposed agreement provides that Anadarko will dedicate its production from Green Canyon Block 608 and 11 other Green Canyon blocks to the processing facilities. The proposed agreement will require a monthly demand charge of slightly over $2 million for five years beginning at the time of project completion and a processing fee based upon production. Anadarko will be entitled to 25% of the net after tax cash proceeds from these facilities after payout, as defined, is attained. The letter of intent does not contain any purchase options, purchase obligations or value guarantees. The previous table does not include any amounts related to this letter of intent.

Drilling and Work Commitments Anadarko has various work related commitments for, among other things, drilling wells, obtaining and processing seismic and fulfilling rig commitments. The above table includes drilling and work related commitments of $163 million, comprised of $45 million in the United States, $53 million in Algeria, $37 million in Canada and $28 million in other international locations. The commitments in Algeria are related primarily to exploration and development contracts with **SONATRACH**, who is the beneficial owner of 5% of the Company's outstanding common stock.

Sales Commitments In Canada, the Company has commitments to deliver gas and oil under fixed price contracts. The gas and oil volumes to be delivered under these contracts are as follows:

	Commitments by Period				
	1 Year	2-3 Years	4-5 Years	Later Years	Total
Natural gas					
Volume — million MMBtu	18	47	16	1	82
Price per MMBtu	$2.16	$1.88	$1.70	$1.54	$1.90
Crude oil					
Volume — million barrels*	2	2	—	—	4

* Price is NYMEX West Texas Intermediate minus $8 per barrel with a floor of $14.40 per barrel and a ceiling of $17.24 per barrel for heavy oil delivered at Hardisty Terminal.

Guarantees Anadarko is guarantor for certain obligations of its wholly-owned and consolidated subsidiaries, which are included in the *Consolidated Financial Statements and Notes* under Item 8 of this Form 10-K. In conjunction with the RME merger, the Company guaranteed all of the outstanding debt of RME and its subsidiaries, which is included in the consolidated debt of the Company. In addition, the Company is guarantor for specific financial obligations of two trona mining affiliates. The investments in these entities, which are not consolidated subsidiaries, are accounted for using the equity method. The Company has guaranteed a portion of certain Industrial Revenue Bonds, amounts due under a revolving credit agreement and letters of credit required for environmental surety bonds. The amount the Company would be obligated to pay should the affiliates default on these obligations would be up to $8 million for environmental surety bonds and $6 million in 2002 and $29 million after 2006 for debt.

Enron The recent financial problems of Enron have had no material adverse effect on the Company. As of December 31, 2001, in connection with several physical and financial contracts, the Company had $10 million, net, in accounts payable to Enron North America and $1 million in accounts receivable from other Enron affiliates. All contracts have been terminated by Anadarko under the terms of the agreements, and $1 million has been charged to expense in 2001. The Company, through purchase accounting entries for the Berkley acquisition, had recorded market value liabilities on four contracts with Enron which were being amortized over the terms of the contract. Upon termination of these contracts in December 2001, the remaining liability of $12 million was no longer required and was recorded as income in 2001.

For additional information on contracts and arrangements the Company enters into from time to time see Item 7a. *Quantitative and Qualitative Disclosures About Market Risk* of this Form 10-K and *Note 5 — Debt, Note 6 — Financial Instruments, Note 15 — Lease Commitments, Note 16 — Pension Plans, Other Postretirement Benefits and Employee Savings Plans* and *Note 17 — Contingencies* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Outlook on Liquidity

Anadarko's net cash from operating activities in 2001 was $3.3 billion compared to $1.5 billion in 2000 and $318 million in 1999. Commodity prices for natural gas and crude oil rose dramatically in 2000 and decreased significantly in the second half of 2001. The Company's original capital expenditure budget for 2002 has been set at $2.0 billion. Cash flow from operations will vary depending upon, among other things, actual commodity prices received throughout the year. The Company intends to adjust capital expenditures to reflect changes in its cash flow from operations. However, due to activities in progress at the beginning of 2002 and the seasonal nature of drilling activity in Alaska and Canada, the Company expects that a disproportionate amount of the 2002 capital expenditure budget will be spent in the first and second quarters of the year. As a result, it is likely that there will be an increase in debt early in the year. Failure of prices to increase later in the year, as expected, could result in increased borrowing throughout the year. Reduced fourth quarter activity in 2002 relative to 2001 could lead to higher working capital requirements and also result in additional borrowing. The Company has a three-year stock buyback program to purchase up to $1 billion in shares of Anadarko common stock. Anticipated stock repurchases for 2002 are not included in the announced capital expenditure budget and could require additional borrowing.

Anadarko believes that operating cash flow and existing or available credit facilities will be adequate to meet its capital and operating requirements for 2002. The Company funds its day-to-day operating expenses and capital expenditures from operating cash flows, supplemented as needed by short-term borrowings of commercial paper, money market loans or credit facility borrowings. To facilitate such borrowings, the Company has in place $750 million in committed credit facilities, which are supplemented by various non-committed credit lines that may be offered by certain banks from time to time at then-quoted rates. It is the Company's policy to limit commercial paper borrowing to levels that are fully back-stopped by unused balances from its committed credit facilities. The Company may choose to refinance certain portions of these short-term borrowings by issuing long-term debt in the public or private debt markets. To facilitate such financings, the Company may file shelf registrations in advance with the SEC. The Company continuously monitors its debt position and coordinates its capital expenditure program with expected cash flows and projected debt repayment schedules. The Company will continue to evaluate funding alternatives, including property sales and additional borrowing, to secure other funds for additional capital expenditures and stock repurchases. At this time, Anadarko has no plans to issue common stock other than through its Dividend Reinvestment and Stock Purchase Plan, through the exercise of stock options or through the Company's Employee Savings Plan and Employee Stock Ownership Plan equity funded contributions. See *Regulatory Matters and Additional Factors Affecting Business* for additional information.

The Company's credit agreements allow for a maximum capitalization ratio of 60% debt, exclusive of the effect of any non-cash write-downs. As of December 31, 2001, Anadarko's capitalization ratio was 44% debt. While there is no specific restriction on paying dividends, under the maximum debt capitalization ratio retained earnings were not restricted as to the payment of dividends at December 31, 2001. The amount of future common stock dividends will depend on earnings, financial conditions, capital requirements and other factors, and will be determined by the Board of Directors on a quarterly basis.

Dividends

In October 2001, the Board of Directors of Anadarko increased the quarterly dividend on the Company's common stock from 5 cents to 7.5 cents per share.

In 2001, Anadarko paid $57 million in dividends to its common stockholders (5 cents per share in the first, second and third quarters and 7.5 cents per share in fourth quarter). In 2000, Anadarko paid $38 million in dividends to its common stockholders (5 cents per share per quarter). The dividend amount in 1999 was $25 million (5 cents per share per quarter). Anadarko has paid a dividend to its common stockholders continuously since becoming an independent company in 1986.

In 2001, 2000 and 1999, the Company also paid $7 million, $11 million and $11 million, respectively, in preferred stock dividends. In 2002, the preferred stock dividends are expected to be $6 million.

Critical Accounting Policies

Financial Statements and Use of Estimates The consolidated financial statements include the accounts of Anadarko and its subsidiaries. All significant intercompany transactions have been eliminated. The Company accounts for investments in affiliated companies (20% to 50% owned) using the equity method of accounting. The financial statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances. In preparing financial statements, Management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

Properties and Equipment The Company uses the full cost method of accounting for exploration and development activities as defined by the SEC. Under this method of accounting, the costs for unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities.

The sum of net capitalized costs and estimated future development and abandonment costs of oil and gas properties and mineral investments is amortized using the unit-of-production method. All other properties are depreciated on the straight-line basis over the useful life of the assets, which ranges from three to 40 years.

Proved Reserves Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGLs that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically as demonstrated by either actual production or conclusive formation tests. Reserves which can be produced economically through application of improved recovery techniques are included in the "proved" classification when successful testing by a pilot project or the operation of an installed program in the reservoir provides support for the engineering analysis on which the project or program was based. "Proved developed" oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods.

The Company emphasizes that the volumes of reserves are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data as well as production performance data. These estimates, made by the Company's engineers, are reviewed and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to uneconomic conditions.

Costs Excluded Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent costs of investments in unproved properties and major development projects. Anadarko excludes these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed quarterly to determine if impairment has occurred. Any impairment is transferred to the costs to be amortized (the DD&A pool) or a charge is made against earnings for those international operations where a reserve base has not yet been established. For international operations where a reserve base has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results or relinquishing drilling rights. Costs excluded for oil and gas properties are generally classified and evaluated as significant or individually insignificant properties.

Significant properties, comprised primarily of costs associated with domestic offshore blocks, Alaska, the Land Grant and other international areas, are individually evaluated each quarter by the Company's exploration and engineering staff. Non-producing leases are evaluated based on the progress of the Company's exploration program to date. Exploration costs are transferred to the DD&A pool upon completion of drilling individual wells. The Land Grant has been in active evaluation to determine an exploration program for this acreage. The Land Grant's mineral interests (both working and royalty interests) are owned by the Company in perpetuity. All other significant properties are evaluated over a five- to ten- year period, depending on the lease term.

Insignificant properties are comprised primarily of costs associated with onshore properties in the United States and Canada. Non-producing leases are impaired over a three- to five- year period based on the average lease period. Exploration costs are transferred to the DD&A pool upon completion.

Capitalized Interest SFAS No. 34, "Capitalization of Interest Costs," provides standards for the capitalization of interest costs as part of the historical cost of acquiring assets. FASB-Interpretation (FIN) No. 33 provides guidance for the application of SFAS No. 34 to the full cost method of accounting for oil and gas properties. Under FIN No. 33, costs of investments in unproved properties and major development projects, on which DD&A expense is not currently taken and on which exploration or development activities are in progress, qualify for capitalization of interest. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt by the amount of costs excluded. Capitalized interest cannot exceed gross interest expense. As costs excluded are transferred to the DD&A pool, the associated capitalized interest is also transferred to the DD&A pool.

Ceiling Test Companies that use the full cost method of accounting for oil and gas exploration and development activities are required to perform a ceiling test each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed on a country-by-country basis. The test determines a limit, or ceiling, on the book value of oil and gas properties. That limit is basically the after tax present value of the future net cash flows from proved crude oil and natural gas reserves. This ceiling is compared to the net book value of the oil and gas properties reduced by any related deferred income tax liability. If the net book value reduced by the related deferred income taxes exceeds the ceiling, an impairment or non-cash write down is required. A ceiling test impairment can give Anadarko a significant loss for a particular period; however, future DD&A expense would be reduced. Shown below is a summary of the ceiling test calculation and description of the major components.

Ceiling Test Calculation

Present Value of Oil and Gas Properties (PV 10)
+ Costs Excluded
− Income Taxes
= Ceiling

Net Oil and Gas Properties and Equipment
− Deferred Income Tax Liability
= Net Investment

Ceiling − Net Investment = Cushion (Write-off) After Income Taxes

Present Value of Oil and Gas Properties (PV 10) Estimates of future net cash flows from proved reserves of gas, oil, condensate and NGLs are made in accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." The present value of oil and gas properties represents the estimated future net cash flows from proved oil and gas reserves, discounted using a prescribed 10% discount rate. Proved oil and gas reserves are estimated quantities of natural gas, crude oil, condensate and NGLs that can be produced economically as demonstrated by actual production or conclusive formation tests. These estimates, which are determined by the Company's engineers, are reviewed and revised as reservoir performance, prices and other economic conditions change. Future net revenues are calculated based on estimated production volumes generally using the oil and gas prices in effect on the last day of the quarter, held flat for the life of the reserves. Future net revenues are reduced by estimated future production and development costs based on quarter-end cost levels, assuming continuation of existing economic conditions.

Due to the volatility of commodity prices, the oil and gas prices on the last day of the quarter significantly impact the calculation of the PV 10. At year-end 2001, Anadarko's ceiling tests were based on NYMEX prices of $2.74 per Mcf for natural gas and $19.78 per barrel for crude oil. The NYMEX prices are adjusted by location and quality differentials, as appropriate, to determine Anadarko's realized prices. The present value of future net cash flows does not purport to be an estimate of the fair market 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 gas.

Costs Excluded Costs excluded are capitalized costs of investments in unproved properties and major development projects. These costs are excluded from capitalized costs being amortized through DD&A expense. Anadarko excludes all costs until proved reserves are found or until it is determined that the costs are impaired. When proved reserves are found, the decrease in costs excluded is offset by an increase in PV 10; thereby generally increasing the ceiling. When proved reserves are not found, the decrease in costs excluded is not offset by an increase in PV 10; thereby decreasing the ceiling.

Income Taxes Future income taxes are based on the existing tax rates applied to the difference between the total of the present value of the future net cash flows plus costs excluded less the tax basis of the oil and gas properties. The effect of tax loss carryforwards and credits is considered in determining income taxes.

Net Oil and Gas Properties and Equipment Net oil and gas properties and equipment are the capitalized costs related to oil and gas activities less the accumulated DD&A. Under the full cost method of accounting the costs for unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. The net capitalized costs are depreciated using the unit-of-production method. Net properties and equipment increase due to capital expenditures or acquisitions and decrease due to DD&A expense, property divestitures or ceiling test impairments.

Deferred Income Tax Liability Deferred income taxes related only to oil and gas properties are included in the deferred income tax liability.

Derivative Financial Instruments Anadarko uses derivative financial instruments for various purposes and carefully monitors the credit worthiness of each counter-party. Effective January 2001, derivative financial instruments utilized to manage or reduce commodity price risk related to the Company's equity production were accounted for under the provisions of SFAS No. 133 "Accounting for Derivative Instruments and for Hedging Activities." Under this statement, all derivatives are carried on the balance sheet at fair value. Realized gains/losses and option premiums are recognized in the statement of income when the underlying physical gas and oil production is sold. Accordingly, realized derivative gains/losses are generally offset by similar changes in the realized prices of the underlying physical gas and oil production. Realized derivative gains/losses are reflected in the average sales price of the physical gas and oil production.

Accounting for unrealized gains/losses is dependent on whether the derivative financial instruments have been designated and qualify as part of a hedging relationship. Derivative financial instruments may be designated as a hedge of exposure to changes in fair values, cash flows or foreign currencies, if certain conditions are met.

If the hedged exposure is to changes in fair value, the gains/losses on the derivative financial instrument, as well as the offsetting losses/gains on the hedged item, are recognized currently in earnings. Consequently, if gains/losses on the derivative financial instrument and the related hedge item do not completely offset, the difference (i.e., ineffective portion of the hedge) is recognized currently in earnings.

If the hedged exposure is a cash flow exposure, the effective portion of the gains/losses on the derivative financial instrument is reported as a component of accumulated other comprehensive income and reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The ineffective portion of the gains/losses from the derivative financial instrument, if any, as well as any amounts excluded from the assessment of the cash flow hedges' effectiveness are recognized currently in other (income) expense. Effective July 2001, the Company implemented Derivatives Implementation Group Issue G20, "Cash Flow Hedges: Assessing and Measuring the Effectiveness of a Purchased Option Used in a Cash Flow Hedge," which provides guidance for assessing the effectiveness on total changes in an option's cash flows rather than only on changes in the option's intrinsic value. Time value changes were previously being recognized in current earnings since the Company excluded time value changes from its assessment of hedge effectiveness.

If the hedged exposure is a foreign currency exposure, the accounting is similar to the accounting for fair value and cash flow hedges. Unrealized gains/losses on derivative financial instruments that do not meet the conditions to qualify for hedge accounting are recognized currently in earnings.

Derivative financial instruments, as well as physical delivery purchase and sale contracts, utilized in the Company's energy trading activities and in the management of price risk associated with the Company's firm transportation keep-whole commitment (see *Derivative Financial Instruments* under Item 7a of this Form 10-K) are accounted for under the mark-to-market accounting method pursuant to Emerging Issues Task Force Issue 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." Under this method, the derivatives and physical delivery contracts are revalued in each accounting period and premiums and unrealized gains/losses are recorded in the statement of income and carried as assets or liabilities on the balance sheet.

The Company's derivative financial instruments associated with the marketing and trading activities are generally either exchange traded or valued by reference to a commodity that is traded in a liquid market. Valuation is determined by reference to readily available public data. Option valuations are based on the Black-Scholes option pricing model and verified against third-party quotations. The fair value of the short-term portion of the firm transportation keep-whole agreement is calculated with actively quoted natural gas basis prices. Basis is the difference in value between gas at various delivery points and the NYMEX gas futures contract price. Management believes that natural gas basis price quotes beyond the next twelve months are not reliable indicators of fair value due to decreasing liquidity. Accordingly, the fair value of the long-term portion is estimated based on historical natural gas basis prices, discounted at a 10% per year. Management also periodically evaluates the supply and demand factors (such as expected drilling activity, anticipated pipeline construction projects, expected changes in demand at pipeline delivery points, etc.) that may impact the future market value of the firm transportation capacity to determine if the estimated fair value should be adjusted.

New Accounting Principles

SFAS No. 142 SFAS No. 142, "Goodwill and Other Intangible Assets," requires discontinuing amortization of goodwill after year-end 2001 and requires that goodwill be tested for impairment. The impairment test requires allocating goodwill and all other assets and liabilities to business levels referred to as reporting units. The fair value of each reporting unit that has goodwill is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value (including goodwill) then a second test is performed to determine the amount of the impairment.

If the second test is necessary, the fair value of the reporting unit's individual assets and liabilities is deducted from the fair value of the reporting unit. This difference represents the implied fair value of goodwill, which is compared to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the amount of the impairment.

The goodwill impairment test is performed annually, and also at interim dates upon the occurrence of significant events. Significant events include: a significant adverse change in legal factors or business climate; an adverse action or assessment by a regulator; a more-likely-than-not expectation that a reporting unit or significant portion of a reporting unit will be sold; significant adverse trends in current and future oil and gas prices; nationalization of any of the Company's oil and gas properties; or, significant increases in a reporting unit's carrying value relative to its fair value.

The initial goodwill impairment test is required to be performed using an effective date of January 1, 2002. The Company is in the process of assessing the impact of adopting SFAS No. 142. Anadarko does not expect any initial goodwill impairment.

SFAS No. 143 SFAS No. 143, "Accounting of Asset Retirement Obligations," requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset and will be effective for the Company in January 2003. The Company is evaluating the impact of SFAS No. 143.

SFAS No. 144 SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 requires that one accounting model be used for long-lived assets to be disposed of by sale, whether previously held and used or newly acquired, and broadens the presentation of discontinued operations to include more disposal transactions. The adoption of SFAS No. 144 as of January 2002 had no impact on the Company's financial statements.

For additional information on the Company's accounting policies see *Note 1* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Regulatory Matters and Additional Factors Affecting Business

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, and those statements preceded by, followed by or that otherwise include the words "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. Such statements are subject to various risks and uncertainties, and actual results could differ materially from those expressed or implied by such statements due to a number of factors in addition to those discussed below and elsewhere in this Form 10-K and in the Company's other public filings, press releases and discussions with Company management. Anadarko undertakes no obligation to publicly update or revise any forward looking statements.

Commodity Pricing and Demand Crude oil prices continue to be affected by political developments worldwide, pricing decisions and production quotas of OPEC and the volatile trading patterns in the commodity futures markets. Natural gas prices also continue to be highly volatile. In periods of sharply lower commodity prices, the Company may curtail production and capital spending projects, as well as delay or defer drilling wells in certain areas because of lower cash flows. Changes in crude oil and natural gas prices can impact the Company's determination of proved reserves and the Company's calculation of the standardized measure of discounted future net cash flows relating to oil and gas reserves. In addition, demand for oil and gas in the U.S. and worldwide may affect the Company's level of production.

Under the full cost method of accounting, a non-cash charge to earnings related to the carrying value of the Company's oil and gas properties on a country-by-country basis may be required when prices are low. Whether the Company will be required to take such a charge depends on the prices for crude oil and natural gas at the end of any quarter, as well as the effect of both capital expenditures and changes to proved reserves during that quarter. While this non-cash charge can give Anadarko a significant reported loss for the period, future expenses for DD&A will be reduced.

Environmental and Safety The Company's oil and gas operations and properties are subject to numerous federal, state and local laws and regulations relating to environmental protection from the time oil and gas projects commence until abandonment. These laws and regulations govern, among other things, the amounts and types of substances and materials that may be released into the environment, the issuance of permits in connection with exploration, drilling and production activities, the release of emissions into the atmosphere, 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 the Company's failure to comply with them or for any contamination resulting from the Company's operations.

Anadarko takes the issue of environmental stewardship very seriously and works diligently to comply with applicable environmental and safety rules and regulations. Compliance with such laws and regulations has not had a material effect on the Company's operations or financial condition in the past. However, because environmental laws and regulations are becoming increasingly more stringent, there can be no assurances that such laws and regulations or any environmental law or regulation enacted in the future will not have a material effect on the Company's operations or financial condition.

For a description of certain environmental proceedings in which the Company is involved, see *Note 17 — Contingencies* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Exploration and Operating Risks The Company's business is subject to all of the operating risks normally associated with the exploration for and production of oil and gas, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, oil and gas wells or formations or production facilities and other property and injury to persons. As protection against financial loss resulting from these operating hazards, the Company maintains insurance coverage, including certain physical damage, employer's liability, comprehensive general liability and worker's compensation insurance. Although Anadarko is not fully insured against all risks in its business, the Company believes that the coverage it maintains is customary for companies engaged in similar operations. The occurrence of a significant event against which the Company is not fully insured could have a material adverse effect on the Company's financial position.

Development Risks The Company is 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; manufacturing and delivery schedules of critical equipment; and commercial arrangements for pipelines and related equipment to transport and market hydrocarbons. In large development projects, these uncertainties are usually resolved, but delays and differences between estimated and actual timing of critical events are commonplace and may, therefore, affect the forward-looking statements related to large development projects.

Domestic Governmental Risks The domestic operations of the Company have been, and at times in the future may be, affected by political developments and by federal, state and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations.

Foreign Operations Risk The Company's operations in areas outside the U.S. are subject to various risks inherent in foreign operations. These risks may include, among other things, loss of revenue, property and equipment as a result of hazards such as expropriation, war, insurrection and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations and other uncertainties arising out of foreign government sovereignty over the Company's international operations. The Company's international operations may also be adversely affected by laws and policies of the United States affecting foreign trade and taxation. To date, the Company's international operations have not been materially affected by these risks.

Competition 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. The Company's competitors include the major oil companies, independent oil and gas concerns, 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.

Other Regulatory agencies in certain states and countries have authority to issue permits for seismic exploration and the drilling of wells, regulate well spacing, prevent the waste of oil and gas resources through proration and regulate environmental matters.

Operations conducted by the Company on federal oil and gas leases must comply with numerous regulatory restrictions, including various nondiscrimination statutes. Additionally, certain operations must be conducted pursuant to appropriate permits issued by the Bureau of Land Management and the Minerals Management Service of the U.S. Department of the Interior. In addition to the standard permit process, federal leases and most international concessions require a complete environmental impact assessment prior to authorizing an exploration or development plan.

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 numerous claims by employees of third-party contractors alleging exposure to asbestos and benzene while working at a refinery in Corpus Christi, Texas, which the Company sold in segments in 1987 and 1989. 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 of the Company, although results of operations and cash flow could be significantly impacted in the reporting periods in which such matters are resolved.

For a description of certain legal proceedings in which the Company is involved, see *Legal Proceedings* under Item 3 of this Form 10-K.

Item 7a. Quantitative and Qualitative Disclosures About Market Risk

Derivative Financial Instruments Anadarko's derivative commodity instruments currently are comprised of futures, swaps and options contracts. The volume of derivative commodity instruments utilized by the Company to hedge its market price risk and in its energy trading operation can vary during the year within the boundaries of its established policy guidelines. See *Critical Accounting Policies* and *Regulatory Matters and Additional Factors Affecting Business* under Item 7 and *Note 1 — Summary of Accounting Policies* and *Note 6 — Financial Instruments* of the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

The majority of the derivatives into which the Company enters have terms of less than 12 months. As of December 31, 2001, the Company had a net unrealized gain of $7 million before taxes (gains of $9 million and losses of $2 million), or $4 million after taxes, on derivative commodity instruments entered into to hedge equity production recorded in accumulated other comprehensive income. Other income for 2001, included $18 million of net gains related to derivative instruments designated as cash flow hedges. These gains were primarily due to the change in the time value of the option contracts that was excluded from the assessment of hedge effectiveness. Based upon an analysis utilizing the actual derivative contractual volumes and assuming a 10% increase in commodity prices, the potential additional loss on these derivative commodity instruments would be approximately $9 million.

As of December 31, 2001 and 2000, the Company had the following volumes under derivative contracts related to its oil and gas producing activities(non-trading activity):

December 31, 2001

Production Period	Instrument Type*	Volumes (million MMBtu)	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*	Qualifies for Hedge Accounting
Natural Gas					
2002	2-way collar	2.3	3.00-5.00	$ 1	yes
2002	3-way collar	6.8	2.20-3.00-4.83	2	yes
2003	2-way collar	2.3	3.00-5.00	1	yes
2003	3-way collar	6.8	2.20-3.00-4.83	1	yes
2004	2-way collar	2.3	3.00-5.00	1	yes
2004	3-way collar	6.9	2.20-3.00-4.83	1	yes
2005	2-way collar	2.3	3.00-5.00	1	yes
2005	3-way collar	6.8	2.20-3.00-4.83	1	yes
2002	Calls sold	10.1	3.66	2	no
2002	Calls purchased	4.9	3.50	—	no
2003	Calls sold	7.4	3.18	(2)	no
2003	Calls purchased	10.2	4.12	2	no
2004	Calls sold	0.7	2.95	—	no
2004	Calls purchased	0.7	2.95	—	no
	Total			$11	

Production Period	Instrument Type*	Volumes (MMBbls)	Average Price ($ per barrel)	Net Fair Value Asset (Liability) *millions*	Qualifies for Hedge Accounting
Crude Oil					
2002	Swaps	0.4	25.56	$ 2	yes
2002	3-way collar	3.3	19.11-23.33-30.51	6	yes
	Total			$ 8	

December 31, 2000

Production Period	Instrument Type*	Volumes (million MMBtu)	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*	Qualifies for Hedge Accounting
Natural Gas					
2001	Swaps	1.1	6.57	$ 10	yes
2001	2-way collar	74.7	4.14-9.24	(16)	yes
2001	3-way collar	5.2	2.20-3.00-4.83	—	yes
2002	2-way collar	2.3	3.00-5.00	(1)	yes
2002	3-way collar	6.8	2.20-3.00-4.83	(3)	yes
2003	2-way collar	2.3	3.00-5.00	(1)	yes
2003	3-way collar	6.8	2.20-3.00-4.83	(3)	yes
2004	2-way collar	2.3	3.00-5.00	—	yes
2004	3-way collar	6.9	2.20-3.00-4.83	(1)	yes
2005	2-way collar	2.3	3.00-5.00	—	yes
2005	3-way collar	6.8	2.20-3.00-4.83	(1)	yes
2001	Calls sold	7.0	11.71	(3)	no
2001	Calls sold	48.6	3.30	(133)	no
2001	Calls purchased	49.5	3.31	136	no
2001	Puts sold	20.9	2.64	—	no
	Total			$ (16)	

Production Period	Instrument Type*	Volumes (MMBbls)	Average Price ($ per barrel)	Net Fair Value Asset (Liability) *millions*	Qualifies for Hedge Accounting
Crude Oil					
2001	2-way collar	4.3	19.32-23.77	$(11)	yes
2001	3-way collar	6.6	18.03-21.00-25.98	(10)	yes
2001	Puts sold	1.8	20.95	1	no
2001	Puts purchased	1.9	18.03	(5)	no
	Total			$(25)	

MMBtu — million British thermal units
MMBbls — million barrels

* A "2-way collar" is a combination of options, a sold call and purchased put. The purchased put establishes a minimum price (the "floor") and the sold call establishes a maximum price (the "ceiling") the Company will receive for the volumes under contract. A "3-way collar" is a combination of options, a sold call, a purchased put and a sold put. The purchased put and sold put establish a floating minimum price (the "floating floor") and the sold call establishes a maximum price (the "ceiling") the Company will receive for the volumes under contract.

Derivative financial instruments utilized in the Company's energy trading activities and in the management of price risk associated with the Company's firm transportation keep-whole commitment are accounted for under the mark-to-market accounting method pursuant to Emerging Issues Task Force Issue 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities". Under this method, the derivatives and physical delivery purchase and sale contracts are revalued in each accounting period and premiums and unrealized gains/losses are immediately recorded in the statement of income and carried as assets or liabilities on the balance sheet. Anadarko's energy marketing and trading business is backed by the Company's substantial oil and gas production and reserves. In the United States and Canada, the Company purchases natural gas produced by other companies in those areas where the Company has substantial production volumes. Third-party purchases allow the Company to aggregate larger volumes of gas and attract larger, more creditworthy customers, which in turn spreads the Company's relatively fixed overhead costs over more gas and can help reduce transportation costs. The Company does not engage in market making practices nor does it trade in any non-energy-related commodities. The marketing and trading business's risk position, most of the time, is a net short position. Excluding the firm transportation keep-whole agreement, essentially all of the Company's trading transactions have a term of less than one year and most are less than three months. The keep-whole agreement will be in effect until the earlier of each contract's expiration date or February 2009. The derivative contracts entered into for trading purposes are typically for terms of less than 12 months. As of December 31, 2001, the Company had a net unrealized loss of $49 million (gains of $42 million and losses of $91 million) on derivative commodity instruments entered into for trading purposes. Losses on derivative commodity instruments are offset by a net unrealized gain of $66 million (gains of $82 million and losses of $16 million) on physical contracts entered into for trading purposes. Based upon an analysis utilizing the actual derivative contractual volumes and assuming a 10% increase in underlying commodity prices, the potential loss on the derivative instruments would be decreased by approximately $4 million.

The energy trading derivative contracts are primarily used to neutralize fixed price exposure in physical delivery agreements and to generate profit on or from exposure to changes in the market price of crude oil and natural gas. As of December 31, 2001 and 2000, the Company had the following volumes under derivative contracts related to its trading activity:

December 31, 2001

Production Period	Instrument Type	Volumes (million MMBtu)	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*
Natural Gas				
2002	Futures sold	23.8	3.34	$ 18
2002	Futures purchased	22.3	3.50	(21)
2002	Swaps	72.3	3.20	(42)
2002	Calls sold	8.5	3.07	1
2002	Calls purchased	12.8	4.09	1
2002	Puts sold	8.3	3.25	(7)
2002	Puts purchased	0.8	2.58	—
2003	Futures sold	1.2	3.51	—
2003	Futures purchased	0.3	3.36	—
2003	Swaps	12.2	3.12	—
	Total			$(50)

Production Period	Instrument Type	Volumes (MMBbls)	Average Price ($ per barrel)	Net Fair Value Asset (Liability) *millions*
Crude Oil				
2002	Futures sold	2.8	19.80	$ (1)
2002	Futures purchased	1.5	20.05	2
2002	Swaps	0.5	21.77	—
2002	Calls sold	0.4	29.50	—
	Total			$ 1

December 31, 2000

Production Period	Instrument Type	Volumes (million MMBtu)	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*
Natural Gas				
2001	Futures sold	9.6	6.48	$(32)
2001	Futures purchased	9.0	7.82	19
2001	Swaps	23.0	5.31	77
2001	Calls sold	1.4	7.67	(2)
2001	Calls purchased	2.0	6.56	4
2001	Puts sold	3.2	7.93	(1)
2002	Swaps	0.5	2.08	(1)
	Total			$ 64

Production Period	Instrument Type	Volumes (MMBbls)	Average Price ($ per barrel)	Net Fair Value Asset (Liability) *millions*
Crude Oil				
2001	Futures sold	1.8	27.40	$ 5
2001	Futures purchased	1.5	27.94	(5)
	Total			$ —

RME was a party to several long-term firm gas transportation agreements that supported their gas marketing program within the gathering, processing and marketing (GPM) business segment, which was sold in 1999 to Duke Energy Field Services, Inc. (Duke). Most of the GPM's firm long-term transportation contracts were transferred to Duke in the GPM disposition. One contract was retained, but is managed and operated by Duke. Anadarko is not responsible for the operations of the contracts and does not utilize the associated transportation assets to transport the Company's natural gas. As part of the GPM disposition, RME agreed to pay Duke if transportation market values fall below the fixed contract transportation rates, while Duke will pay RME if the transportation market values exceed the contract transportation rates (keep-whole agreement). Net payments from Duke for the year ended December 31, 2001 were $161 million. Transportation contracts transferred to Duke in the GPM disposition and the contract not transferred, all of which are included in the keep-whole agreement with Duke, relate to various pipelines. This keep-whole agreement is accounted for on a mark-to-market basis. This keep-whole agreement will be in effect until the earlier of each contract's expiration date or February 2009. During 2001, the Company recognized other income of $91 million ($26 million from the agreement and $65 million from derivative financial instruments). As of December 31, 2001, other current liabilities included $27 million and other long-term liabilities included $80 million related to this agreement. The future gain or loss from this agreement cannot be accurately predicted.

Anticipated discounted and undiscounted liabilities for the firm transportation keep-whole commitment at December 31, 2001 are as follows:

millions	Undiscounted	Discounted
2002	$ 27	$ 27
2003	21	18
2004	27	22
2005	20	15
2006	19	12
Later years	23	13
Total	$137	$107

The Company may periodically use derivative financial instruments to reduce its exposure under the keep-whole agreement to potential decreases in future transportation market values. While the derivatives are intended to reduce the Company's exposure to declines in transportation market rates, they also limit the potential to benefit from market price increases. For the year ended December 31, 2001, the Company recognized other income of $64 million on derivative financial instruments related to transportation rates. At December 31, 2001, other current assets included $25 million of unrealized gains related to this agreement. An analysis of these derivative financial instruments determined that an adverse price movement would not have a material effect on the financial position or results of operations of the Company. Due to decreased liquidity, the use of derivative financial instruments to manage this risk is generally limited to the forward twelve months only.

As of December 31, 2001 and 2000, the Company had the following volumes under derivative contracts related to the firm transportation keep-whole agreement:

December 31, 2001

Production Period	Instrument Type	Volumes (million MMBtu)*	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*
Natural Gas				
2002	Swaps	4.2	8.42	$25

December 31, 2000

Production Period	Instrument Type	Volumes (million MMBtu)**	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*
Natural Gas				
2001	Swaps	13.4	9.08	$12
2001	Calls sold	0.9	9.84	—
	Total			$12

* Represents 2% of the Company's total volumetric exposure under the keep-whole agreement for 2002.

** Represents 6% of the Company's total volumetric exposure under the keep-whole agreement for 2001.

For additional information regarding the Company's marketing and trading portfolio and the firm transportation keep-whole agreement see *Marketing Strategies* under Item 7 of this Form 10-K.

Common Stock Purchase Program In July 2001, the Board of Directors authorized the Company to purchase up to $1 billion in shares of Anadarko common stock. The share purchases may be made from time to time, depending on market conditions. Shares may be purchased either in the open market or through privately negotiated transactions. The repurchase program does not obligate Anadarko to acquire any specific number of shares and may be discontinued at any time. During 2001, the Company purchased 2.2 million shares of common stock for $116 million. In January 2002, the Company purchased an additional 1 million shares of common stock for $50 million.

To enhance the share repurchase program, Anadarko has sold put options to independent third parties. These put options entitle the holder to sell shares of Anadarko common stock to the Company on certain dates at specified prices. During 2001, Anadarko sold put options for the purchase of a total of 5 million shares of Anadarko common stock with a notional amount of $240 million. Put options for 1 million shares were exercised, and put options for 2 million shares expired unexercised in 2001. During 2001, premiums of $15 million were received related to these put options and recorded as an increase to paid-in capital. In January 2002, the Company entered into additional put options for 1 million shares of Anadarko common stock with a notional amount of $46 million and received a $3 million premium. Put options for an additional 1 million shares expired unexercised in 2002. The remaining put options for 2 million shares will expire in March and July 2002, if not exercised. The put options permit a net-share settlement at the Company's option and do not result in a liability on the consolidated balance sheet as of December 31, 2001.

Interest Rate Risk Anadarko is also exposed to risk resulting from changes in interest rates as a result of the Company's variable and fixed interest rate debt. The Company believes the potential effect that reasonably possible near term changes in interest rates may have on the fair value of the Company's various debt instruments is not material.

Foreign Currency Risk The Company's Canadian subsidiaries use the Canadian dollar as their functional currency. The Company's other international subsidiaries use the U.S. dollar as their functional currency. To the extent that business transactions in these countries are not denominated in the respective country's functional currency, the Company is exposed to foreign currency exchange rate risk. In addition, in these subsidiaries, certain asset and liability balances are denominated in currencies other than the subsidiary's functional currency. These asset and liability balances are remeasured in the preparation of the subsidiary's financial statements using a combination of current and historical exchange rates, with any resulting remeasurement adjustments included in net income during the period.

At December 31, 2001 and 2000, a Canadian subsidiary had $187 million and $650 million, respectively, outstanding of fixed-rate notes and debentures denominated in U.S. dollars. During 2001 and 2000, the Company recognized $25 million and $8 million, respectively, of non-cash losses before taxes associated with the remeasurement of this debt. The potential foreign currency remeasurement impact on earnings from a 10% change in the December 31, 2001 Canadian exchange rate would be about $20 million based on the outstanding debt at December 31, 2001.

The Company periodically enters into foreign currency contracts to hedge specific currency exposures from commercial transactions. As a result of the RME merger transaction, the Company acquired foreign currency forward exchange contracts with maturities through October 2004 and recorded a $4 million deferred liability representing the fair value of these contracts. These contracts were determined to be cash flow hedges of Anadarko Canada's future U.S. dollar denominated hydrocarbon sales. This deferred liability will be recognized in earnings when the contracts are settled. The unrealized loss on foreign currency contracts excluding the $4 million unamortized deferred liability at December 31, 2001 and 2000 was $6 million and $2 million, respectively. Approximately $3 million of the after tax unrealized loss was included in accumulated other comprehensive income as of December 31, 2001. No portion of the balance is expected to be reclassified into earnings during 2002. The following table summarizes the Company's open foreign currency positions at December 31, 2001 and 2000:

$ in millions, except foreign currency rates	**2001**	2000
Notional amount — US$	**$ 70**	$ 70
Forward rate	**1.36**	1.36
Market rate	**1.58**	1.48
Decrease in rate	**(0.22)**	(0.12)
Fair value — loss — C$	**$ 15**	$ 8
Fair value — loss — US$	**$ 10**	$ 6

At December 31, 2001 and 2000, the Company's Latin American subsidiaries had foreign deferred tax liabilities denominated in the local currency equivalent totaling $78 million and $98 million, respectively. During 2001 and 2000, the Company recognized tax benefits associated with remeasurement of these deferred tax liabilities of $6 million and $9 million, respectively. In conjunction with the sale of Latin American properties in 2001, the Company indemnified a purchaser for the use of local tax losses denominated in the local currency equivalent totaling $22 million. A gain of $1 million, before taxes, was recognized related to the remeasurement of this liability and is included in other (income) expense for the year ended December 31, 2001. The potential foreign currency remeasurement impact on net earnings from a 10% change in the year-end Latin American exchange rates would be approximately $9 million.

Commodity Price Risk As a result of low natural gas and oil prices at September 30, 2001, Anadarko's capitalized costs of oil and gas properties in the United States, Canada and Argentina exceeded the ceiling limitation and the Company recorded a $2.53 billion ($1.57 billion after taxes) non-cash write-down in the third quarter of 2001. The pre-tax write-down is reflected as additional accumulated depreciation, depletion and amortization. See *Critical Accounting Policies* and *Regulatory Matters and Additional Factors Affecting Business* under Item 7 of this Form 10-K.

Item 8. Financial Statements and Supplementary Data

ANADARKO PETROLEUM CORPORATION
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CONSOLIDATED FINANCIAL STATEMENTS

ANADARKO PETROLEUM CORPORATION
REPORT OF MANAGEMENT

The Management of Anadarko Petroleum Corporation is responsible for the preparation and integrity of all information contained in the accompanying consolidated financial statements. The financial statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances. In preparing the financial statements, Management makes informed judgments and estimates.

Management maintains and relies on the Company's system of internal accounting controls. Although no system can ensure elimination of all errors and irregularities, this system is designed to provide reasonable assurance that assets are safeguarded, transactions are executed in accordance with Management's authorization and accounting records are reliable as a basis for the preparation of financial statements. This system includes the selection and training of qualified personnel, an organizational structure providing appropriate delegation of authority and division of responsibility, the establishment of accounting and business policies for the Company and the conduct of internal audits.

The Board of Directors pursues its responsibility for the consolidated financial information through its Audit Committee, which is composed solely of Directors who are not officers or employees of Anadarko. The Audit Committee recommends to the Board of Directors the selection of independent auditors and reviews their fee arrangements. The Audit Committee meets periodically with Management, the internal auditors and the independent auditors to review that each is carrying out its responsibilities. Both the internal and the independent auditors have full and free access to the Audit Committee to discuss auditing and financial reporting matters.

We believe that Anadarko's policies and procedures, including its system of internal accounting controls, provide reasonable assurance that the financial statements are prepared in accordance with the applicable securities rules and regulations.

John N. Seitz
President and Chief Executive Officer

Michael E. Rose
Executive Vice President, Finance and
Chief Financial Officer

ANADARKO PETROLEUM CORPORATION
INDEPENDENT AUDITORS' REPORT

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, 2001 and 2000, and the related consolidated statements of income, stockholders' equity, comprehensive income and cash flows for each of the years in the three-year period ended December 31, 2001. 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 auditing standards generally accepted in the United States of America. 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, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative financial instruments, and effective January 1, 2000, the Company changed its method of accounting for foreign crude oil inventories.

KPMG LLP

Houston, Texas
January 31, 2002, except as to Note 18,
which is as of March 12, 2002

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENT OF INCOME

millions except per share amounts	**Years Ended December 31** **2001**	2000	1999
Revenues			
Gas sales	**$2,893**	$1,591	$ 353
Oil and condensate sales	**1,380**	948	247
Natural gas liquids sales	**255**	264	88
Marketing sales	**3,776**	2,637	1,016
Minerals and other	**65**	60	2
Total	**8,369**	5,500	1,706
Costs and Expenses			
Marketing purchases	**3,704**	2,638	972
Operating expenses	**716**	438	179
Administrative and general	**247**	180	102
Depreciation, depletion and amortization	**1,154**	593	218
Other taxes	**247**	128	36
Provisions for doubtful accounts	**—**	23	—
Impairments related to oil and gas properties	**2,546**	50	24
Amortization of goodwill	**73**	31	—
Total	**8,687**	4,081	1,531
Operating Income (Loss)	**(318)**	1,419	175
Other (Income) Expense			
Merger expenses	**45**	67	—
Interest expense	**92**	93	74
Other (income) expense	**(65)**	(167)	(4)
Total	**72**	(7)	70
Income (Loss) Before Income Taxes	**(390)**	1,426	105
Income Taxes			
Income taxes	**(183)**	602	62
Effect of change in Canadian income tax rate	**(31)**	—	—
Total	**(214)**	602	62
Net Income (Loss) Before Cumulative Effect of Change in Accounting Principle	**$ (176)**	$ 824	$ 43
Preferred Stock Dividends	**7**	11	11
Net Income (Loss) Available to Common Stockholders Before Cumulative Effect of Change in Accounting Principle	**$ (183)**	$ 813	$ 32
Cumulative Effect of Change in Accounting Principle	**5**	17	—
Net Income (Loss) Available to Common Stockholders	**$ (188)**	$ 796	$ 32
Per Common Share			
Net income (loss) — before change in accounting principle — basic	**$(0.73)**	$ 4.42	$ 0.25
Net income (loss) — before change in accounting principle — diluted	**$(0.73)**	$ 4.25	$ 0.25
Change in accounting principle — basic	**$(0.02)**	$(0.09)	$ —
Change in accounting principle — diluted	**$(0.02)**	$(0.09)	$ —
Net income (loss) — basic	**$(0.75)**	$ 4.32	$ 0.25
Net income (loss) — diluted	**$(0.75)**	$ 4.16	$ 0.25
Dividends	**$0.225**	$ 0.20	$ 0.20
Average Number of Common Shares Outstanding — Basic	**250**	184	125
Average Number of Common Shares Outstanding — Diluted	**250**	193	126

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEET

millions	December 31 2001	2000
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 37**	$ 199
Accounts receivable, net of allowance:		
Customers	**532**	981
Others	**486**	395
Other current assets	**146**	319
Total	**1,201**	1,894
Properties and Equipment		
Original cost (includes unproved properties of $3,573 and $2,898 as of December 31, 2001 and 2000, respectively)	**20,088**	15,843
Less accumulated depreciation, depletion and amortization	**6,451**	2,832
Net properties and equipment — based on the full cost method of accounting for oil and gas properties	**13,637**	13,011
Other Assets	**503**	368
Goodwill	**1,534**	1,348
Less accumulated amortization	**104**	31
Goodwill, net of amortization	**1,430**	1,317
	$16,771	$16,590
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 1,132**	$ 1,256
Accrued expenses	**257**	420
Current portion, notes and debentures	**412**	—
Total	**1,801**	1,676
Long-term Debt	**4,638**	3,984
Other Long-term Liabilities		
Deferred income taxes	**3,451**	3,633
Other	**516**	511
Total	**3,967**	4,144
Stockholders' Equity		
Preferred stock, par value $1.00 per share (2.0 million shares authorized, 0.1 million and 0.2 million shares issued as of December 31, 2001 and 2000, respectively)	**103**	200
Common stock, par value $0.10 per share (450.0 million shares authorized, 254.1 million and 253.3 million shares issued as of December 31, 2001 and 2000, respectively)	**25**	25
Paid-in capital	**5,336**	5,303
Retained earnings	**1,276**	1,521
Treasury stock (2.2 million shares as of December 31, 2001)	**(116)**	—
Deferred compensation and ESOP (0.9 million and 1.1 million shares as of December 31, 2001 and 2000, respectively)	**(96)**	(121)
Executives and Directors Benefits Trust, at market value (2.0 million shares as of December 31, 2001 and 2000)	**(114)**	(145)
Accumulated other comprehensive income (loss)		
Foreign currency translation adjustments	**(46)**	3
Minimum pension liability	**(3)**	—
Total	**(49)**	3
Total	**6,365**	6,786
Commitments and Contingencies	**—**	—
	$16,771	$16,590

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

millions	Years Ended December 31 2001	2000	1999
Preferred Stock			
Balance at beginning of year	**$ 200**	$ 200	$ 200
Preferred stock repurchased	**(97)**	—	—
Balance at end of year	**103**	200	200
Common Stock			
Balance at beginning of year	**25**	13	12
Common stock issued	**—**	12	1
Balance at end of year	**25**	25	13
Paid-in Capital			
Balance at beginning of year	**5,303**	634	361
Common stock issued	**51**	4,592	267
Revaluation to market for Executives and Directors Benefits Trust	**(31)**	77	6
Preferred stock repurchased	**13**	—	—
Balance at end of year	**5,336**	5,303	634
Retained Earnings			
Balance at beginning of year	**1,521**	764	757
Net income (loss)	**(181)**	807	43
Dividends paid — preferred	**(7)**	(11)	(11)
Dividends paid — common	**(57)**	(39)	(25)
Balance at end of year	**1,276**	1,521	764
Treasury Stock			
Balance at beginning of year	**—**	—	—
Purchase of treasury stock	**(116)**	—	—
Balance at end of year	**(116)**	—	—
Deferred Compensation and ESOP			
Balance at beginning of year	**(121)**	(8)	(9)
Issuance of restricted stock	**(15)**	(82)	(2)
Acquisition of ESOP	**—**	(74)	—
Amortization of restricted stock and release of ESOP shares	**40**	43	3
Balance at end of year	**(96)**	(121)	(8)
Executives and Directors Benefits Trust			
Balance at beginning of year	**(145)**	(68)	(62)
Revaluation to market	**31**	(77)	(6)
Balance at end of year	**(114)**	(145)	(68)
Other Comprehensive Income (Loss)			
Balance at beginning of year	**3**	—	—
Foreign currency translation adjustments	**(49)**	3	—
Minimum pension liability	**(3)**	—	—
Balance at end of year	**(49)**	3	—
Stockholders' Equity	**$6,365**	$6,786	$1,535

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

millions	Years Ended December 31 **2001**	2000	1999
Net Income (Loss) Available to Common Stockholders	**$(188)**	$796	$ 32
Other Comprehensive Income (Loss), net of taxes			
Unrealized gain (loss) on derivatives:			
Cumulative effect of accounting change (net of taxes of $3 for the year ended December 31, 2001)	**(5)**	—	—
Reclassification of cumulative effect of accounting change included in net income (net of taxes of $(2) for the year ended December 31, 2001)	**4**	—	—
Unrealized gain during the period (net of taxes of $(19) for the year ended December 31, 2001)	**32**	—	—
Reclassification adjustment for gains included in net income (net of taxes of $18 for the year ended December 31, 2001)	**(31)**	—	—
Total unrealized gain (loss) on derivatives	**—**	—	—
Foreign currency translation adjustments	**(49)**	3	—
Minimum pension liability (net of taxes of $1 for the year ended December 31, 2001)	**(3)**	—	—
Total	**(52)**	3	—
Comprehensive Income (Loss)	**$(240)**	$799	$ 32

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS

millions	Years Ended December 31 **2001**	2000	1999
Cash Flow from Operating Activities			
Net income (loss) before cumulative effect of change in accounting principle	**$ (176)**	$ 824	$ 43
Adjustments to reconcile net income (loss) before cumulative effect of change in accounting principle to net cash provided by operating activities:			
Depreciation, depletion and amortization	**1,155**	594	220
Impairments related to oil and gas properties	**2,546**	50	24
Amortization of goodwill	**73**	31	—
Non-cash merger expenses	**15**	33	—
Interest expense — zero coupon debentures	**13**	10	—
Deferred income taxes	**(319)**	457	26
Provisions for doubtful accounts	**—**	23	—
Other non-cash items	**122**	(147)	—
	3,429	1,875	313
(Increase) decrease in accounts receivable	**544**	(703)	(78)
Increase (decrease) in accounts payable and accrued expenses	**(534)**	415	99
Other items — net	**(118)**	(51)	(16)
Net cash provided by operating activities	**3,321**	1,536	318
Cash Flow from Investing Activities			
Additions to properties and equipment	**(3,316)**	(1,708)	(680)
Acquisition costs, net of cash acquired	**(940)**	(53)	—
Sales and retirements of properties and equipment	**138**	61	129
Proceeds from the sale of assets to be leased, net	**—**	—	15
Net cash used in investing activities	**(4,118)**	(1,700)	(536)
Cash Flow from Financing Activities			
Additions to debt	**2,788**	345	300
Retirements of debt	**(1,977)**	(321)	(282)
Increase in accounts payable, banks	**24**	56	—
Dividends paid	**(64)**	(50)	(36)
Retirement of preferred stock	**(84)**	—	—
Purchase of treasury stock	**(116)**	—	—
Issuance of common stock	**49**	288	264
Net cash provided by financing activities	**620**	318	246
Effect of Exchange Rate Changes on Cash	**15**	—	—
Net Increase (Decrease) in Cash and Cash Equivalents	**(162)**	154	28
Cash and Cash Equivalents at Beginning of Year	**199**	45	17
Cash and Cash Equivalents at End of Year	**$ 37**	$ 199	$ 45

See accompanying notes to consolidated financial statements.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2001, 2000 and 1999

1. Summary of 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 hard minerals business through non-operated joint ventures and royalty arrangements in several coal, trona (natural soda ash) and industrial mineral mines. The terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its subsidiaries. The principal subsidiaries of Anadarko are: RME Petroleum Company; RME Holding Company; Anadarko Canada Energy Ltd.; Anadarko Canada Corporation (Anadarko Canada); RME Land Corp.; and, Anadarko Algeria Company, LLC (Anadarko Algeria).

Principles of Consolidation and Use of Estimates The consolidated financial statements include the accounts of Anadarko and its subsidiaries. All significant intercompany transactions have been eliminated. The Company accounts for investments in affiliated companies (20% to 50% owned) using the equity method of accounting. The financial statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances. Certain amounts for prior years have been reclassified to conform to the current presentation. In preparing financial statements, Management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

Changes in Accounting Principles In 2001, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, which provides guidance for accounting for derivative instruments and hedging activities. The change was effective January 2001 and the related cumulative adjustment to net income was a decrease of $8 million ($5 million after taxes, or $0.02 per share) and the cumulative adjustment to accumulated other comprehensive income was a decrease of $8 million ($5 million after taxes).

Effective January 2000, the Company changed its method of accounting for the carrying value of foreign crude oil inventories from market to cost. This change was made as a result of a change in position on the carrying value of inventories communicated by the United States Securities and Exchange Commission (SEC). The related adjustment to net income was a decrease of $19 million ($17 million after taxes, or $0.09 per share) in 2000.

Properties and Equipment The Company uses the full cost method of accounting for exploration and development activities as defined by the SEC. Under this method of accounting, the costs for unsuccessful, as well as successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a cost center.

The sum of net capitalized costs and estimated future development and abandonment costs of oil and gas properties and mineral investments is amortized using the unit-of-production method. All other properties are stated at original cost and are depreciated on the straight-line basis over the useful life of the assets, which ranges from three to 40 years. Properties and equipment carrying values do not purport to represent replacement or market values.

Operating fees received related to the properties in which the Company owns an interest are netted against operating expenses. Fees received in excess of costs incurred are recorded as a reduction to the full cost pool.

1. Summary of Accounting Policies (Continued)

Costs Excluded Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent costs of investments in unproved properties and major development projects. Anadarko excludes these costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed quarterly to determine if impairment has occurred. Any impairment is transferred to the costs to be amortized (the depreciation, depletion and amortization (DD&A) pool) or a charge is made against earnings for those international operations where a reserve base has not yet been established. For international operations where a reserve base has not yet been established, an impairment requiring a charge to earnings may be indicated through evaluation of drilling results or relinquishing drilling rights. Costs excluded for oil and gas properties are generally classified and evaluated as significant or individually insignificant properties.

Significant properties, comprised primarily of costs associated with domestic offshore blocks, Alaska, the Land Grant and other international areas, are individually evaluated each quarter by the Company's exploration and engineering staff. Non-producing leases are evaluated based on the progress of the Company's exploration program to date. Exploration costs are transferred to the DD&A pool upon completion of drilling individual wells. The Land Grant has been in active evaluation to determine an exploration program for this acreage. The Land Grant's mineral interests (both working and royalty interests) are owned by the Company in perpetuity. All other significant properties are evaluated over a five- to ten-year period, depending on the lease term.

Insignificant properties are comprised primarily of costs associated with onshore properties in the United States and Canada. Non-producing leases are impaired over a three- to five-year period based on the average lease period. Exploration costs are transferred to the DD&A pool upon completion.

Capitalized Interest SFAS No. 34, "Capitalization of Interest Costs," provides standards for the capitalization of interest costs as part of the historical cost of acquiring assets. Financial Accounting Standards Board Interpretation (FIN) No. 33 provides guidance for the application of SFAS No. 34 to the full cost method of accounting for oil and gas properties. Under FIN No. 33, costs of investments in unproved properties and major development projects, on which DD&A expense is not currently taken and on which exploration or development activities are in progress, qualify for capitalization of interest. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt by the amount of costs excluded. Capitalized interest cannot exceed gross interest expense. As costs excluded are transferred to the DD&A pool, the associated capitalized interest is also transferred to the DD&A pool.

Ceiling Test The Company limits, on a country-by-country basis, the capitalized costs of proved oil and gas properties, net of accumulated DD&A and the related deferred income taxes, to the estimated future net cash flows from proved oil and gas reserves, generally using prices in effect at the end of the period held flat for the life of production, discounted at 10%, net of related tax effects, plus the cost of unevaluated properties and major development projects excluded from the costs being amortized. If capitalized costs exceed this limit, the excess is charged to expense and reflected as additional accumulated DD&A.

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGLs that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered proved if they can be produced economically as demonstrated by either actual production or conclusive formation tests. The Company emphasizes that the volumes of reserves are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates, made by the Company's engineers, are reviewed and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to uneconomic conditions.

1. Summary of Accounting Policies (Continued)

Revenues Natural gas, oil and NGLs sales revenues are recorded using the sales method, whereby the Company recognizes sales revenues based on the amount of gas, oil and NGLs sold to purchasers on its behalf. Gas, oil and NGLs marketing and gathering revenues are shown as marketing sales. Commodity trading positions are marked to market, with the related gains and losses included in marketing sales.

Effective January 2000, the Company adopted the provisions of the SEC Staff Accounting Bulletin No. 101, "Revenue Recognition in Financial Statements," which summarized the SEC staff's views in applying generally accepted accounting principles to revenue recognition issues. As a result, marketing sales are shown as revenues, offset by marketing purchases that are shown as costs and expenses, rather than including only the margin as revenues.

Derivative Financial Instruments Effective January 2001, derivative financial instruments utilized to manage or reduce commodity price risk related to the Company's equity production were accounted for under the provisions of SFAS No. 133. Under this statement, all derivatives are carried on the balance sheet at fair value. Realized gains/losses and option premiums are recognized in the statement of income when the underlying physical gas and oil production is sold. Accordingly, realized derivative gains/losses are generally offset by similar changes in the realized prices of the underlying physical gas and oil production. Realized derivative gains/losses are reflected in the average sales price of the physical gas and oil production.

Accounting for unrealized gains/losses is dependent on whether the derivative financial instruments have been designated and qualify as part of a hedging relationship. Derivative financial instruments may be designated as a hedge of exposure to changes in fair values, cash flows or foreign currencies, if certain conditions are met.

If the hedged exposure is to changes in fair value, the gains/losses on the derivative financial instrument, as well as the offsetting losses/gains on the hedged item, are recognized currently in earnings. Consequently, if gains/losses on the derivative financial instrument and the related hedge item do not completely offset, the difference (i.e., ineffective portion of the hedge) is recognized currently in earnings.

If the hedged exposure is a cash flow exposure, the effective portion of the gains/losses on the derivative financial instrument is reported as a component of accumulated other comprehensive income and reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The ineffective portion of the gains/losses from the derivative financial instrument, if any, as well as any amounts excluded from the assessment of the cash flow hedges' effectiveness are recognized currently in other (income) expense. Effective July 2001, the Company implemented Derivatives Implementation Group Issue G20, "Cash Flow Hedges: Assessing and Measuring the Effectiveness of a Purchased Option Used in a Cash Flow Hedge," which provides guidance for assessing the effectiveness on total changes in an option's cash flows rather than only on changes in the option's intrinsic value. Time value changes were previously being recognized in current earnings since the Company excluded time value changes from its assessment of hedge effectiveness.

If the hedged exposure is a foreign currency exposure, the accounting is similar to the accounting for fair value and cash flow hedges. Unrealized gains/losses on derivative financial instruments that do not meet the conditions to qualify for hedge accounting are recognized currently in earnings.

Derivative financial instruments, as well as physical delivery purchase and sale contracts, utilized in the Company's energy trading activities and in the management of price risk associated with the Company's firm transportation keep-whole commitment are accounted for under the mark-to-market accounting method pursuant to Emerging Issues Task Force Issue 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." Under this method, the derivatives and physical delivery contracts are revalued in each accounting period and premiums and unrealized gains/losses are recorded in the statement of income and carried as assets or liabilities on the balance sheet.

1. Summary of Accounting Policies (Continued)

The Company's derivative financial instruments associated with the marketing and trading activities are generally either exchange traded or valued by reference to a commodity that is traded in a liquid market. Valuation is determined by reference to readily available public data. Option valuations are based on the Black-Scholes option pricing model and verified against third-party quotations. The fair value of the short-term portion of the firm transportation keep-whole agreement is calculated with actively quoted natural gas basis prices, while the fair value of the long-term portion is estimated based on historical natural gas basis prices. See Note 6.

Prior to the adoption of SFAS No. 133, derivative financial instruments utilized to manage or reduce commodity price risk related to the Company's equity production (with the exception of net written options) were accounted for under the hedge or deferral method of accounting. Under this method, realized gains/losses and option premiums were recognized in the statement of income when the underlying physical oil and gas production was sold. Accordingly, realized gains/losses were generally offset by similar changes in the realized prices of the underlying physical oil and gas production. Realized derivative gains/losses were reflected in the average sales price of the physical oil and gas production. Margin deposits, deferred realized gains/losses and premiums were included in other current assets or liabilities. Unrealized gains/losses were not recorded.

Realized gains and losses resulting from the Company's interest rate swap agreements were included in interest expense on a current basis. The swap agreements effectively converted a portion of the Company's fixed interest rate debt to variable interest rate debt. The Company's interest rate swap agreements did not qualify for hedge accounting. Therefore, unrealized gains/losses were recognized currently in earnings and reflected in other (income) expense. At December 31, 2001, the Company had no outstanding interest rate swaps.

Inventories Materials and supplies and company-produced commodity inventories are stated at the lower of average cost or market. Inventories consisting of commodities purchased from third parties in connection with the Company's marketing and trading business are carried at fair value. Company produced commodities, when sold from inventory, are charged to expense using the average-cost method. Commodities purchased from third parties, when sold from inventory, are charged to expense using market price.

Goodwill Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired and liabilities assumed in the merger with Union Pacific Resources Group Inc., subsequently renamed RME Holding Company (RME), and the acquisition of Berkley Petroleum Corp. (Berkley) (See Note 2) and, through year-end 2001, was amortized on a straight-line basis over 20 years. The Company assessed the recoverability of goodwill by determining whether the amortization of the goodwill balance over its remaining life could be recovered through undiscounted future operating cash flows of the acquired operation. The amount of goodwill impairment, if any, would have been measured based on projected discounted future operating cash flows using a discount rate reflecting the Company's average cost of funds. Effective January 2002, goodwill is no longer amortized. See New Accounting Principles.

Environmental Contingencies The Company accrues for losses associated with environmental remediation obligations when such losses are probable and can be reasonably estimated. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the time of the completion of the remedial feasibility study. These accruals are adjusted as further information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

Income Taxes The Company files various U.S. federal, state and foreign income tax returns. Deferred federal, state and foreign income taxes are provided on all significant temporary differences, except for those

1. Summary of Accounting Policies (Continued)

essentially permanent in duration, between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases.

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

Stock-based Compensation The Company accounts for stock-based compensation under the intrinsic value method. Under this method, the Company records no compensation expense for stock options granted to employees or directors when the exercise price of options granted is equal to or above the fair market value of Anadarko's common stock on the date of grant.

Earnings Per Share The Company's basic earnings (loss) per share (EPS) amounts have been computed based on the average number of shares of common stock outstanding for the period. Diluted EPS amounts include the effect of the Company's outstanding stock options and performance-based stock awards under the treasury stock method and outstanding put options under the reverse treasury stock method. Diluted EPS amounts also include the net effect of the Company's convertible debentures and Zero Yield Puttable Contingent Debt Securities (ZYP-CODES) assuming the conversions occurred at the beginning of the year or the date of issuance, if later.

New Accounting Principles SFAS No. 141, "Business Combinations," requires that the purchase method of accounting be used for all business combinations. SFAS No. 141 also specifies criteria that must be met in order for intangible assets acquired in a purchase method business combination to be recognized and reported apart from goodwill. The adoption of SFAS No. 141 as of July 2001 had no impact on the Company's financial statements.

SFAS No. 142, "Goodwill and Other Intangible Assets," requires discontinuing amortization of goodwill after year-end 2001 and requires that goodwill be tested for impairment. The impairment test requires allocating goodwill and all other assets and liabilities to business levels referred to as reporting units. The fair value of each reporting unit that has goodwill is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value (including goodwill) then a second test is performed to determine the amount of the impairment.

If the second test is necessary, the fair value of the reporting unit's individual assets and liabilities is deducted from the fair value of the reporting unit. This difference represents the implied fair value of goodwill, which is compared to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the amount of the impairment.

The goodwill impairment test is performed annually, and also at interim dates upon the occurrence of significant events. Significant events include: a significant adverse change in legal factors or business climate; an adverse action or assessment by a regulator; a more-likely-than-not expectation that a reporting unit or significant portion of a reporting unit will be sold; significant adverse trends in current and future oil and gas prices; nationalization of any of the Company's oil and gas properties; or, significant increases in a reporting unit's carrying value relative to its fair value.

The initial goodwill impairment test is required to be performed using an effective date of January 1, 2002. The Company is in the process of assessing the impact of adopting SFAS No. 142. Anadarko does not expect any initial goodwill impairment.

SFAS No. 143, "Accounting for Asset Retirement Obligations," requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset and will be effective for the Company in January 2003. The Company is evaluating the impact of SFAS No. 143.

SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 requires that one

1. Summary of Accounting Policies (Continued)

accounting model be used for long-lived assets to be disposed of by sale, whether previously held and used or newly acquired, and broadens the presentation of discontinued operations to include more disposal transactions. The adoption of SFAS No. 144 as of January 2002 had no impact on the Company's financial statements.

2. Merger and Acquisitions

On July 14, 2000, the Company merged with Union Pacific Resources Group Inc., subsequently renamed RME. Each share of common stock of RME issued and outstanding was converted into 0.455 shares of Anadarko common stock. The merger was treated as a tax-free reorganization and accounted for as a purchase business combination under generally accepted accounting principles. Under this method of accounting, the Company's historical operating results for periods prior to the merger are the same as Anadarko's historical operating results. At the date of the merger, the assets and liabilities of Anadarko remained based upon their historical costs, and the assets and liabilities of RME were recorded at their estimated fair market values.

The following is a calculation of the purchase price:

millions, except per share amounts	
Shares of common stock issued	114
Average of Anadarko stock price per share around the merger announcement	$35.58
Fair value of stock issued	$4,060
Add: Fair value of vested RME employee stock options assumed by Anadarko, less common stock issuance costs	100
	4,160
Add: Capitalized merger costs	143
Purchase price	$4,303

Capitalized merger costs relate primarily to severance and relocation costs of RME employees ($84 million), professional fees directly related to the merger ($44 million) and other direct transaction costs ($15 million).

The following is the allocation of the purchase price to specific assets and liabilities based on estimates of fair values and costs:

millions	
Current assets	$ 661
Properties and equipment	8,243
Other assets	219
Goodwill	1,293
Current liabilities	969
Long-term debt	2,507
Deferred income taxes	2,465
Other long-term liabilities	315
Stockholders' equity	$4,160

The pro forma results for 2000 and 1999 are a result of combining the statement of income of Anadarko with the statement of income of RME adjusted for (1) certain costs that RME had expensed under the successful efforts method of accounting that are capitalized under the full cost method of accounting; (2) DD&A expense of RME calculated in accordance with the full cost method of accounting applied to the

2. Merger and Acquisitions (Continued)

adjusted basis of the properties acquired using the purchase method of accounting; (3) decreases to interest expense for the capitalization of interest on significant investments in unevaluated properties and major development projects and partly offset by the revaluation of RME debt under the purchase method of accounting, including the elimination of historical debt issuance amortization costs; (4) issuance of Anadarko common stock and stock options pursuant to the merger agreement; and, (5) the related income tax effects of these adjustments based on the applicable statutory tax rates. It should be noted that the pro forma results do not include any merger expenses.

The following table presents the unaudited pro forma results of the Company as though the RME merger had occurred on January 1, 1999. Pro forma results are not necessarily indicative of actual results.

millions, except per share amounts	**2000**	**1999**
Revenues	$7,385	$4,442
Net income available to common stockholders	$1,088	$ 328
Earnings per share — basic	$ 4.45	$ 1.37
Earnings per share — diluted	$ 4.30	$ 1.36

Merger costs of $41 million and $67 million for the years ended December 31, 2001 and 2000, respectively, were expensed related to the RME merger. These merger costs relate primarily to the issuance of stock for retention of employees, deferred compensation, transition, integration, hiring and relocation costs, vesting of restricted stock and stock options and retention bonuses.

In March 2001, Anadarko acquired Canadian based Berkley for C$11.40 per share for an aggregate equity value of US$779 million plus the assumption of US$236 million of debt. Goodwill recorded related to the Berkley acquisition was $244 million. Merger costs of $3 million were expensed for the year ended December 31, 2001 related to the Berkley acquisition.

In August 2001, the Company completed the acquisition of Gulfstream Resources Canada Limited (Gulfstream). The Gulfstream shares were purchased for C$2.65 per share, for a total value of US$118 million plus the assumption of US$10 million of debt. Merger costs of $1 million were expensed for the year ended December 31, 2001 related to the Gulfstream acquisition.

3. Inventories

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

millions	**2001**	2000
Materials and supplies	**$ 61**	$44
Crude oil	**22**	20
Natural gas	**18**	15
Total	**$101**	$79

4. Properties and Equipment

A summary of the original cost of properties and equipment by classification follows:

millions	**2001**	2000
Oil and gas properties	**$18,047**	$14,031
Mineral properties	**1,212**	1,213
Gathering facilities	**295**	194
General properties	**534**	405
Total	**$20,088**	$15,843

Oil and gas properties include costs of $3.57 billion and $2.90 billion at December 31, 2001 and 2000, respectively, which were excluded from capitalized costs being amortized. These amounts represent costs associated with unevaluated properties and major development projects. At December 31, 2001, the Company's investment in countries where reserves have not been established was $53 million.

During 2001, 2000 and 1999, the Company made provisions for impairments of U.S. and international properties of $2.55 billion, $50 million and $24 million, respectively, which were related to oil and gas properties. As a result of low oil and gas prices at September 30, 2001, Anadarko's capitalized costs of oil and gas properties primarily in the United States, Canada and Argentina exceeded the ceiling limitation and the Company recorded a $2.53 billion ($1.57 billion after taxes) non-cash write-down in the third quarter of 2001. The pre-tax write-down is reflected as additional accumulated DD&A in the accompanying balance sheet. The remaining 2001 impairment of $18 million related to exploration activities in the United Kingdom and Ghana. In 2000, the Company recorded international impairments of $50 million for exploration activities in the United Kingdom, Tunisia and other international locations. International impairments were recorded in 1999 for exploration activities in Eritrea and the Faroe Islands totaling $24 million.

Total interest costs incurred during 2001, 2000 and 1999 were $301 million, $193 million and $96 million, respectively. Of these amounts, the Company capitalized $209 million, $100 million and $22 million during 2001, 2000 and 1999, respectively. Capitalized interest is included as part of the cost of oil and gas properties. The interest rates for capitalization are based on the Company's weighted average cost of borrowings used to finance the expenditures applied to costs excluded.

In addition to capitalized interest, the Company also capitalized internal costs of $178 million, $124 million and $81 million during 2001, 2000 and 1999, respectively. These internal costs were directly related to exploration and development activities and are included as part of the cost of oil and gas properties.

5. Debt

A summary of debt follows:

	2001		2000	
millions	**Principal**	**Carrying Value**	**Principal**	**Carrying Value**
Notes Payable, Banks*	**$ 228**	**$ 228**	$ 199	$ 199
Commercial Paper*	**226**	**226**	—	—
Long-term Portion of Capital Lease	**9**	**9**	12	12
8¼% Notes due 2001	**—**	**—**	100	100
6.8% Debentures due 2002	**88**	**88**	250	247
6¾% Notes due 2003	**73**	**73**	100	100
5⅞% Notes due 2003	**83**	**83**	100	100
6.5% Notes due 2005	**170**	**164**	200	192
7.375% Debentures due 2006	**88**	**87**	250	247
7% Notes due 2006	**174**	**170**	200	194
6.75% Notes due 2008	**116**	**110**	160	151
7.8% Debentures due 2008	**11**	**11**	150	150
7.3% Notes due 2009	**85**	**82**	160	156
6¾% Notes due 2011	**950**	**910**	—	—
7.05% Debentures due 2018	**114**	**105**	200	183
Zero Coupon Convertible Debentures due 2020	**367**	**367**	355	355
Zero Yield Puttable Contingent Debt Securities due 2021	**650**	**650**	—	—
7.5% Debentures due 2026	**112**	**105**	200	188
7% Debentures due 2027	**54**	**54**	100	100
6.625% Debentures due 2028	**17**	**17**	100	100
7.15% Debentures due 2028	**235**	**212**	370	334
7.20% Debentures due 2029	**135**	**135**	300	300
7.95% Debentures due 2029	**117**	**117**	240	238
7½% Notes due 2031	**900**	**862**	—	—
7.73% Debentures due 2096	**61**	**61**	100	100
7¼% Debentures due 2096	**49**	**49**	100	100
7.5% Debentures due 2096	**83**	**75**	150	138
Total debt	**$5,195**	**5,050**	$4,096	3,984
Less current portion		**412**		—
Total long-term debt		**$4,638**		$3,984

* The average rates in effect December 31, 2001 and 2000 were 2.55% and 6.29%, respectively, for the Notes Payable, Banks. The average rate in effect at December 31, 2001 was 2.59% for Commercial Paper.

As a result of the RME merger transaction, the Company recorded $116 million of debt discount, representing the excess of the carrying value over the fair value of the debt acquired. As a result of the 2001 financial restructuring plan following the Berkley acquisition, an additional $40 million of debt discount was recorded. The $145 million and $112 million of unamortized debt discount as of December 31, 2001 and 2000, respectively, will be amortized over the terms of the debt issues.

Anadarko has noncommitted lines of credit from several banks. The general provisions of these lines of credit provide for Anadarko to borrow funds for terms and rates offered from time to time by the banks. There are no fees associated with these lines of credit.

5. Debt (Continued)

The Company has a commercial paper program that allows Anadarko to borrow funds, at rates as offered, by issuing notes to investors for terms of up to 270 days.

At December 31, 2001, $1.16 billion of notes, debentures and securities will mature or may be put to Anadarko within the next twelve months. In accordance with SFAS No. 6, "Classification of Short-term Obligations Expected to be Refinanced," $750 million of this amount is classified as long-term debt, under the terms of Anadarko's Bank Credit Agreements. The remaining $412 million is classified as short-term debt. At December 31, 2000, the 8¼% Notes due 2001 and notes payable to banks were classified as long-term debt in accordance with SFAS No. 6, under the terms of Anadarko's Bank Credit Agreements.

In March 2000, Anadarko issued $345 million of Zero Coupon Convertible Debentures due March 2020, with a face value at maturity of $690 million. The debentures were issued at a discount and accrue interest at 3.50% annually until reaching face value at maturity; however, interest will not be paid prior to maturity. The debentures were issued at an initial conversion premium of 40% and are convertible into common stock at the option of the holder at any time at a fixed conversion rate. Holders have the right to require Anadarko to repurchase their debentures at a specified price in March 2003, 2008 and 2013. The debentures are redeemable at the option of Anadarko after three years. The net proceeds from the offering were used to repay floating interest rate debt.

In March 2001, Anadarko issued $650 million of ZYP-CODES due 2021 to qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S. The debt securities were priced with a zero coupon, zero yield to maturity and a conversion premium of 38%. The proceeds from the debt securities were used initially to finance costs associated with the acquisition of Berkley. Holders of the ZYP-CODES have the right to require Anadarko to purchase all or a portion of their ZYP-CODES in March 2002, 2004, 2006, 2011 or 2016, at $1,000 per ZYP-CODES. Anadarko will pay the purchase price in cash. See Note 18.

In April 2001, Anadarko Finance Company, a wholly-owned finance subsidiary of Anadarko, issued $1.30 billion in notes as part of the Company's financial restructuring plan. This issuance was made up of $400 million of 6¾% Notes due 2011 and $900 million of 7½% Notes due 2031. In May 2001, Anadarko Finance Company issued an additional $550 million of 6¾% Notes due 2011, bringing the 6¾% Notes to an aggregate total of $950 million. The notes are fully and unconditionally guaranteed by Anadarko. The notes were issued as part of an exchange of securities for other Anadarko debt. The intercompany debt resulting from these transactions is of a long-term investment nature; therefore, foreign currency translation losses of $55 million for 2001 were recorded as a component of other comprehensive income.

At December 31, 2001 and 2000, a Canadian subsidiary had $187 million and $650 million, respectively, outstanding of fixed-rate notes and debentures denominated in U.S. dollars. During 2001 and 2000, the Company recognized $25 million and $8 million, respectively, of non-cash losses before taxes associated with the remeasurement of this debt.

In October 2001, the Company entered into a Revolving Credit Agreement and a 364-Day Revolving Credit Agreement. Each agreement provides for a $225 million principal amount and expires in 2004 and 2002, respectively. In October 2001, Anadarko Canada, a wholly-owned subsidiary of Anadarko, entered into a 364-Day Canadian Credit Agreement. The agreement provides for a US$300 million principal amount and expires in 2002. The agreement is fully and unconditionally guaranteed by Anadarko. Interest rates for these bank commitments are based on either the prime rate, Fed Funds rate, London interbank borrowing rate or Bankers' Acceptance rate. As of December 31, 2001, the Company had $69 million outstanding under the Canadian Credit Agreement.

Total sinking fund and installment payments related to debt for the five years ending December 31, 2006 are shown below. The payments related to the redemption of the ZYP-CODES, 6.8% Debentures due 2002

5. Debt (Continued)

and a portion of the notes payable to banks are included in the amounts shown in a manner consistent with the terms for repayment of the Anadarko's Bank Credit Agreements.

millions	
2002	$412
2003*	381
2004*	225
2005	170
2006	262

* Holders of the Zero Coupon Convertible Debentures due 2020 may put the debentures to the Company in 2003 at the accrued value of $383 million. Holders of the remaining $30 million of ZYP-CODES outstanding may put the ZYP-CODES to the Company in 2004. See Note 18. These put options have not been reflected in the table above.

6. Financial Instruments

The following information provides the carrying value and estimated fair value of the Company's financial instruments:

millions	Carrying Amount	Fair Value
2001		
Cash and cash equivalents	**$ 37**	**$ 37**
Total debt	**5,050**	**5,170**
Commodity derivative financial instruments (including firm transportation keep-whole agreement)		
Asset	**105**	**105**
Liability	**(217)**	**(217)**
Foreign currency derivative financial instruments	**(10)**	**(10)**
2000		
Cash and cash equivalents	$ 199	$ 199
Total debt (including interest rate swaps)	3,984	3,980
Commodity derivative financial instruments (including firm transportation keep-whole agreement)		
Asset	294	462
Liability	(263)	(398)
Foreign currency derivative financial instruments	(4)	(6)

Cash and cash equivalents The carrying amount reported on the balance sheet approximates fair value.

Debt The fair value of debt at December 31, 2001 and 2000 is the value the Company would have to pay to retire the debt, including any premium or discount to the debt holder for the differential between stated interest rate and year-end market rate. The fair values are based on quoted market prices from Standard and Poor's Bond Guide or Bloomberg L.P. and, where such quotes were not available, on the average rate in effect at year-end.

Commodity Derivative Financial Instruments The Company is exposed to price risk from changing commodity prices. Management believes it is prudent to minimize the variability in cash flows on a portion of its oil and gas production. To meet this objective, the Company enters into various types of commodity

6. Financial Instruments (Continued)

derivative financial instruments to manage fluctuations in cash flows resulting from changing commodity prices. These instruments may include futures, swaps and options and essentially all of these instruments have a term of less than one year, with most having a term of less than three months. As of December 31, 2001, the Company had outstanding derivative financial instruments which hedged 4% of the Company's expected 2002 natural gas production and 8% of crude oil production.

Anadarko also enters into commodity derivative financial instruments (options, futures and swaps) for trading purposes with the objective of generating profits from exposure to changes in the market price of natural gas and crude oil. Commodity derivative financial instruments also provide a way to meet customers' pricing requirements while achieving a price structure consistent with the Company's overall pricing strategy. In addition, the Company uses swap agreements to reduce exposure to losses on its firm transportation keep-whole commitment with Duke Energy Field Services, Inc. (Duke).

Futures contracts are generally used to fix the price of expected future oil and gas sales at major industry trading locations; e.g., Henry Hub, Louisiana for gas and Cushing, Oklahoma for oil. Settlements of futures contracts are guaranteed by the New York Mercantile Exchange or the International Petroleum Exchange and have nominal credit risk. Swap agreements are generally used to fix or float the price of oil and gas at the Company's market locations. Swap agreements are also used to fix the price differential between the price of gas at Henry Hub and various other market locations. Swap agreements expose the Company to credit risk to the extent the counter-party is unable to meet its monthly settlement commitment. The Company carefully monitors the creditworthiness of each counter-party. In addition, the Company routinely exercises its contractual right to net realized gains against realized losses in settling with its swap counterparties. Options are generally used to fix a floor and/or a ceiling price (a "collar") for the Company's expected future oil and gas sales. The Company buys/sells options through exchanges as well as in the over the counter market.

Cash Flow Hedges At December 31, 2001, the Company had option and swap contracts in place to fix floor and/or ceiling prices on a portion of expected future sales of equity gas and oil production. The Company has option contracts to hedge its exposure to the variability in future cash flows associated with sales of equity oil production that extend through December 2002 and associated with sales of gas production that extend through December 2005. Swap agreements to hedge the Company's exposure to the variability in future cash flows associated with sales of equity oil production extend through December 2002. As of December 31, 2001, the Company had a net unrealized gain of $7 million before taxes (gains of $9 million and losses of $2 million), or $4 million after taxes, on derivative commodity instruments entered into to hedge equity production recorded in accumulated other comprehensive income. Other income for the year ended December 31, 2001 included $18 million of net gains, primarily due to the change in the time value of the option contracts, that was excluded from the assessment of hedge effectiveness. Approximately $5 million of net gains in the accumulated other comprehensive income balance as of December 31, 2001 are expected to be reclassified into gas and oil sales during 2002 as the hedged transactions occur.

6. Financial Instruments (Continued)

As of December 31, 2001 and 2000, the Company had the following volumes under derivative contracts related to its oil and gas producing activities (non-trading activity):

December 31, 2001

Production Period	Instrument Type*	Volumes (million MMBtu)	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*	Qualifies for Hedge Accounting
Natural Gas					
2002	2-way collar	2.3	3.00-5.00	$ 1	yes
2002	3-way collar	6.8	2.20-3.00-4.83	2	yes
2003	2-way collar	2.3	3.00-5.00	1	yes
2003	3-way collar	6.8	2.20-3.00-4.83	1	yes
2004	2-way collar	2.3	3.00-5.00	1	yes
2004	3-way collar	6.9	2.20-3.00-4.83	1	yes
2005	2-way collar	2.3	3.00-5.00	1	yes
2005	3-way collar	6.8	2.20-3.00-4.83	1	yes
2002	Calls sold	10.1	3.66	2	no
2002	Calls purchased	4.9	3.50	—	no
2003	Calls sold	7.4	3.18	(2)	no
2003	Calls purchased	10.2	4.12	2	no
2004	Calls sold	0.7	2.95	—	no
2004	Calls purchased	0.7	2.95	—	no
	Total			$11	

Production Period	Instrument Type*	Volumes (MMBbls)	Average Price ($ per barrel)	Net Fair Value Asset (Liability) *millions*	Qualifies for Hedge Accounting
Crude Oil					
2002	Swaps	0.4	25.56	$2	yes
2002	3-way collar	3.3	19.11-23.33-30.51	6	yes
	Total			$8	

6. Financial Instruments (Continued)

December 31, 2000

Production Period	Instrument Type*	Volumes (million MMBtu)	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*	Qualifies for Hedge Accounting
Natural Gas					
2001	Swaps	1.1	6.57	$ 10	yes
2001	2-way collar	74.7	4.14-9.24	(16)	yes
2001	3-way collar	5.2	2.20-3.00-4.83	—	yes
2002	2-way collar	2.3	3.00-5.00	(1)	yes
2002	3-way collar	6.8	2.20-3.00-4.83	(3)	yes
2003	2-way collar	2.3	3.00-5.00	(1)	yes
2003	3-way collar	6.8	2.20-3.00-4.83	(3)	yes
2004	2-way collar	2.3	3.00-5.00	—	yes
2004	3-way collar	6.9	2.20-3.00-4.83	(1)	yes
2005	2-way collar	2.3	3.00-5.00	—	yes
2005	3-way collar	6.8	2.20-3.00-4.83	(1)	yes
2001	Calls sold	7.0	11.71	(3)	no
2001	Calls sold	48.6	3.30	(133)	no
2001	Calls purchased	49.5	3.31	136	no
2001	Puts sold	20.9	2.64	—	no
	Total			$ (16)	

Production Period	Instrument Type*	Volumes (MMBbls)	Average Price ($ per barrel)	Net Fair Value Asset (Liability) *millions*	Qualifies for Hedge Accounting
Crude Oil					
2001	2-way collar	4.3	19.32-23.77	$(11)	yes
2001	3-way collar	6.6	18.03-21.00-25.98	(10)	yes
2001	Puts sold	1.8	20.95	1	no
2001	Puts purchased	1.9	18.03	(5)	no
	Total			$(25)	

MMBtu — million British thermal units
MMBbls — million barrels

* A "2-way collar" is a combination of options, a sold call and purchased put. The purchased put establishes a minimum price (the "floor") and the sold call establishes a maximum price (the "ceiling") the Company will receive for the volumes under contract. A "3-way collar" is a combination of options, a sold call, a purchased put and a sold put. The purchased put and sold put establish a floating minimum price (the "floating floor") and the sold call establishes a maximum price (the "ceiling") the Company will receive for the volumes under contract.

6. Financial Instruments (Continued)

Fair Value Hedge The Company had a swap agreement in place to convert a gas contract from a fixed price to a market sensitive price. The term of this swap agreement, as well as the underlying gas contract, expired October 31, 2001.

Trading Activity As of December 31, 2001 and 2000, the Company had the following volumes under derivative contracts related to its trading activity:

December 31, 2001

Production Period	Instrument Type	Volumes (million MMBtu)	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*
Natural Gas				
2002	Futures sold	23.8	3.34	$ 18
2002	Futures purchased	22.3	3.50	(21)
2002	Swaps	72.3	3.20	(42)
2002	Calls sold	8.5	3.07	1
2002	Calls purchased	12.8	4.09	1
2002	Puts sold	8.3	3.25	(7)
2002	Puts purchased	0.8	2.58	—
2003	Futures sold	1.2	3.51	—
2003	Futures purchased	0.3	3.36	—
2003	Swaps	12.2	3.12	—
	Total			$(50)

Production Period	Instrument Type	Volumes (MMBbls)	Average Price ($ per barrel)	Net Fair Value Asset (Liability) *millions*
Crude Oil				
2002	Futures sold	2.8	19.80	$(1)
2002	Futures purchased	1.5	20.05	2
2002	Swaps	0.5	21.77	—
2002	Calls sold	0.4	29.50	—
	Total			$ 1

6. Financial Instruments (Continued)

December 31, 2000

Production Period	Instrument Type	Volumes (million MMBtu)	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*
Natural Gas				
2001	Futures sold	9.6	6.48	$(32)
2001	Futures purchased	9.0	7.82	19
2001	Swaps	23.0	5.31	77
2001	Calls sold	1.4	7.67	(2)
2001	Calls purchased	2.0	6.56	4
2001	Puts sold	3.2	7.93	(1)
2002	Swaps	0.5	2.08	(1)
	Total			$ 64

Production Period	Instrument Type	Volumes (MMBbls)	Average Price ($ per barrel)	Net Fair Value Asset (Liability) *millions*
Crude Oil				
2001	Futures sold	1.8	27.40	$ 5
2001	Futures purchased	1.5	27.94	(5)
	Total			$ —

Firm Transportation Keep-whole Agreement RME was a party to several long-term firm gas transportation agreements that supported their gas marketing program within their gathering, processing and marketing (GPM) business segment, which was sold in 1999 to Duke. Most of the GPM's firm long-term transportation contracts were transferred to Duke in the GPM disposition. One contract was retained, but is managed and operated by Duke. Anadarko is not responsible for the operations of the contracts and does not utilize the associated transportation assets to transport the Company's natural gas. As part of the GPM disposition, RME agreed to pay Duke if transportation market values fall below the fixed contract transportation rates, while Duke will pay RME if the transportation market values exceed the contract transportation rates (keep-whole agreement). Transportation contracts transferred to Duke in the GPM disposition and the contract not transferred, all of which are included in the keep-whole agreement with Duke, relate to various pipelines. This keep-whole agreement will be in effect until the earlier of each contract's expiration date or February 2009. The Company may periodically use derivative financial instruments to manage the price risk associated with this agreement. This keep-whole agreement and any oil and gas derivative financial instruments are accounted for on a mark-to-market basis. The Company recognized other income of $91 and $175 million during 2001 and 2000, respectively. As of December 31, 2001 and 2000, other current assets included $25 million and $129 million, accounts payable included $27 million and zero and other long-term liabilities included $80 million and $89 million, respectively, related to the keep-whole agreement and associated derivative financial instruments.

The fair value of the short-term portion of the firm transportation keep-whole agreement is calculated with actively quoted natural gas basis prices. Basis is the difference in value between gas at various delivery points and the NYMEX gas futures contract price. Management believes that natural gas basis price quotes beyond the next twelve months are not reliable indicators of fair value due to decreasing liquidity. Accordingly, the fair value of the long-term portion is estimated based on historical natural gas basis prices, discounted at 10% per year. Management also periodically evaluates the supply and demand factors (such as

6. Financial Instruments (Continued)

expected drilling activity, anticipated pipeline construction projects, expected changes in demand at pipeline delivery points, etc.) that may impact the future market value of the firm transportation capacity to determine if the estimated fair value should be adjusted.

Anticipated discounted and undiscounted liabilities for the firm transportation keep-whole commitment at December 31, 2001 are as follows:

millions	Undiscounted	Discounted
2002	$ 27	$ 27
2003	21	18
2004	27	22
2005	20	15
2006	19	12
Later years	23	13
Total	$137	$107

As of December 31, 2001 and 2000, the Company had the following volumes under derivative contracts related to the firm transportation keep-whole agreement:

December 31, 2001

Production Period	Instrument Type	Volumes (million MMBtu)*	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*
Natural Gas				
2002	Swaps	4.2	8.42	$25

December 31, 2000

Production Period	Instrument Type	Volumes (million MMBtu)**	Average Price ($ per MMBtu)	Net Fair Value Asset (Liability) *millions*
Natural Gas				
2001	Swaps	13.4	9.08	$12
2001	Calls sold	0.9	9.84	—
	Total			$12

* Represents 2% of the Company's total volumetric exposure under the keep-whole agreement for 2002.
** Represents 6% of the Company's total volumetric exposure under the keep-whole agreement for 2001.

Interest Rate Swaps Interest rate swap agreements were entered into to offset a portion of the effect of the Company's fixed rate long-term debt. In 1999, Anadarko entered into a 29.5 year swap agreement with a notional value of $200 million whereby the Company received a fixed interest rate and paid a floating interest rate indexed to the 3-month London interbank borrowing rate. The swap agreement was cancelled in March 2001 at no cost to the Company. During 1996, Anadarko entered into a 10-year swap agreement with a notional value of $100 million whereby the Company received a fixed interest rate and paid a floating interest rate indexed to the 3-month London interbank borrowing rate. This agreement was terminated in May 2001 at no cost to the Company.

6. Financial Instruments (Continued)

Foreign Currency Risk Anadarko's Canadian subsidiaries use the Canadian dollar as their functional currency. The Company's other international subsidiaries use the U.S. dollar as their functional currency. To the extent that business transactions in these countries are not denominated in the respective country's functional currency, the Company is exposed to foreign currency exchange rate risk. In addition, in these subsidiaries, certain asset and liability balances are denominated in currencies other than the subsidiary's functional currency. These asset and liability balances are remeasured for the preparation of the subsidiary's financial statements using a combination of current and historical exchange rates, with any resulting remeasurement adjustments included in net income during the period.

The Company periodically enters into foreign currency contracts to hedge specific currency exposures from commercial transactions. As a result of the RME merger transaction, the Company acquired foreign currency forward exchange contracts with maturities through October 2004 and recorded a $4 million deferred liability representing the fair value of these contracts. These contracts were determined to be cash flow hedges of Anadarko Canada's future U.S. dollar denominated hydrocarbon sales. This deferred liability will be recognized in earnings when the contracts are settled. The unrealized loss on foreign currency contracts excluding the $4 million unamortized deferred liability at December 31, 2001 and 2000 was $6 million and $2 million, respectively. Approximately $3 million of the after tax unrealized loss was included in accumulated other comprehensive income as of December 31, 2001. No portion of the balance is expected to be reclassified into earnings during 2002. The following table summarizes the Company's open foreign currency positions at December 31, 2001 and 2000:

	2001	2000
$ in millions, except foreign currency rates		
Notional amount — US$	**$ 70**	$ 70
Forward rate	**1.36**	1.36
Market rate	**1.58**	1.48
Decrease in rate	**(0.22)**	(0.12)
Fair value — loss — C$	**$ 15**	$ 8
Fair value — loss — US$	**$ 10**	$ 6

At December 31, 2001 and 2000, the Company's Latin American subsidiaries had foreign deferred tax liabilities denominated in the local currency equivalent totaling $78 million and $98 million, respectively. During 2001 and 2000, the Company recognized tax benefits associated with remeasurement of these deferred tax liabilities of $6 million and $9 million, respectively. In conjunction with the sale of Latin American properties in 2001, the Company indemnified a purchaser for the use of local tax losses denominated in local currency equivalent totaling $22 million. A gain of $1 million, before taxes, was recognized related to the remeasurement of this liability and is included in other (income) expense for the year ended December 31, 2001.

7. Preferred Stock

In May 1998, Anadarko issued $200 million of 5.46% Series B Cumulative Preferred Stock in the form of two million Depositary Shares, each Depositary Share representing 1/10th of a share of the 5.46% Series B Cumulative Preferred Stock. The preferred stock has no stated maturity and is not subject to a sinking fund or mandatory redemption. The shares are not convertible into other securities of the Company.

7. Preferred Stock (Continued)

Anadarko has the option to redeem the shares at $100 per Depositary Share on or after May 15, 2008. Holders of the shares are entitled to receive, when, and as declared by the Board of Directors, cumulative cash dividends at an annual dividend rate of $5.46 per Depositary Share.

During 2001, Anadarko repurchased $97 million of preferred stock. The resulting gain of $13 million was recorded to paid-in capital. During 2001, 2000 and 1999, dividends of $54.60 per share (equivalent to $5.46 per Depositary Share) were paid to holders of preferred stock.

8. Common Stock and Stock Options

Following is a schedule of the changes in the Company's shares of common stock:

millions	**2001**	2000	1999
Shares of common stock issued			
Beginning of year	**253**	130	122
Issuance of common stock	**—**	114	7
Exercise of stock options	**1**	6	1
Issuance of restricted stock	**—**	2	—
Issuance of shares for unearned employee stock ownership plan	**—**	1	—
End of year	**254**	253	130
Shares of common stock held in treasury			
Beginning of year	**—**	—	—
Purchase of treasury stock	**2**	—	—
End of year	**2**	—	—
Shares of common stock held for unearned employee stock ownership plan			
Beginning of year	**1**	—	—
Issuance of stock	**—**	1	—
End of year	**1**	1	—
Shares of common stock held for Executives and Directors Benefits Trust			
Beginning of year	**2**	2	2
End of year	**2**	2	2
Shares of common stock outstanding at end of year	**249**	250	128

In the fourth quarter of 2001, dividends of 7.5 cents per share were paid to holders of common stock. For the first, second and third quarters of 2001 and for each quarter of 2000 and 1999, dividends of 5 cents per share were paid to holders of common stock. The Company's credit agreements allow for a maximum capitalization ratio of 60% debt, exclusive of the effect of any non-cash writedowns. While there is no specific restriction on paying dividends, under the maximum debt capitalization ratio retained earnings were not restricted as to the payment of dividends at December 31, 2001. Under the most restrictive provisions of the various credit agreements in effect at December 31, 2000, retained earnings were not restricted as to the payment of dividends at December 31, 2000.

On July 13, 2000, the stockholders of Anadarko approved an increase in the authorized number of Anadarko common shares from 300 million to 450 million. On July 14, 2000, each share of common stock of RME issued and outstanding was converted into 0.455 shares of Anadarko common stock with approximately 114 million shares issued to the stockholders of RME.

8. Common Stock and Stock Options (Continued)

In May 1999, Anadarko issued 6 million shares of common stock. Aggregate proceeds from the offering were approximately $241 million after all expenses.

The Anadarko Dividend Reinvestment and Stock Purchase Plan (DRIP) offers the opportunity to reinvest dividends and provides an alternative to traditional methods of buying, holding and selling Anadarko common stock. The DRIP provides the Company with a means of raising additional capital for general corporate purposes. In September 1999, the Company filed a registration statement with the SEC that permits the issuance of up to 4.5 million additional shares of common stock under the DRIP.

Under the Anadarko Stockholders Rights Plan, Rights were attached automatically to each outstanding share of common stock in November 1998. Each Right, at the time it becomes exercisable and transferable apart from the common stock, entitles stockholders to purchase from the Company 1/1000th of a share of a new series of junior participating preferred stock at an exercise price of $175. The Right will be exercisable only if a person or group acquires 15% or more of common stock or announces a tender offer or exchange offer, the consummation of which would result in ownership by a person or group of 15% or more of the common stock. The Board of Directors may elect to exchange and redeem the Rights. The Rights expire in November 2008.

In July 2001, the Board of Directors authorized the Company to purchase up to $1 billion in shares of Anadarko common stock. The share purchases may be made from time to time, depending on market conditions. Shares may be purchased either in the open market or through privately negotiated transactions. The repurchase program does not obligate Anadarko to acquire any specific number of shares and may be discontinued at any time. During 2001, the Company purchased 2.2 million shares of common stock for $116 million. In January 2002, the Company purchased an additional 1 million shares of common stock for $50 million. During 2000 and 1999, the Company acquired treasury stock only as a result of stock option exercises, restricted stock transactions or buyback of shares, which were unsolicited from stockholders.

To enhance the share repurchase program, Anadarko has sold put options to independent third parties. These put options entitle the holder to sell shares of Anadarko common stock to the Company on certain dates at specified prices. During 2001, Anadarko sold put options for the purchase of a total of 5 million shares of Anadarko common stock with a notional amount of $240 million. Put options for 1 million shares were exercised, and put options for 2 million shares expired unexercised in 2001. During 2001, premiums of $15 million were received related to these put options and recorded as an increase to paid-in capital. In January 2002, the Company entered into additional put options for 1 million shares of Anadarko common stock with a notional amount of $46 million and received a $3 million premium. Put options for an additional 1 million shares expired unexercised in 2002. The remaining put options for 2 million shares will expire in March and July 2002, if not exercised. The put options permit a net-share settlement at the Company's option and do not result in a liability on the consolidated balance sheet as of December 31, 2001.

As of December 31, 2001 and 2000, the Company had 2 million shares of common stock in the Anadarko Petroleum Corporation Executives and Directors Benefits Trust (Trust) to secure present and future unfunded benefit obligations of the Company. These benefit obligations are provided for under pension plans and deferred compensation plans for certain employees and non-employee directors of the Company. The obligations included in Other Long-term Liabilities – Other are $52 million and $25 million as of December 31, 2001 and 2000, respectively. The shares issued to the Trust are not considered outstanding for quorum or voting calculations, but the Trust receives dividends. Under the treasury stock method, the shares are not included in the calculation of EPS. The fair market value of these shares is included in common stock and paid-in capital and as a reduction to stockholders' equity. See Note 16.

Key employees may be granted options to purchase shares of Anadarko common stock and other stock related awards under the 1993 and the 1999 Stock Incentive Plans. Stock options are granted at the fair market value of Anadarko stock on the date of grant and have a maximum term of 11 years from the date of grant.

8. Common Stock and Stock Options (Continued)

In addition, the Plans provide that shares of common stock may be granted as restricted stock. Generally, restricted stock is subject to forfeiture restrictions and cannot be sold, transferred or disposed of during the restriction period. The holders of the restricted stock have all the rights of 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 such shares. During 2001, 2000 and 1999, the Company issued 0.2 million, 1.2 million and 0.1 million shares, respectively, of restricted stock with a weighted-average grant date fair value of $61.26, $50.21 and $35.87 per share, respectively. In 2001, 2000 and 1999, expense related to restricted stock grants was $14 million, $8 million and $2 million, respectively. In 2001 and 2000, 0.03 million and 0.5 million shares, respectively, of unrestricted common stock with a weighted-average grant date fair value of $65.71 and $48.53 per share, respectively, were issued related to the RME merger transaction. Merger expenses in 2001 and 2000 of $2 million and $25 million, respectively, were recognized related to these shares. Also due to the RME merger transaction, 0.2 million shares of unrestricted common stock with a weighted-average grant date fair value of $48.53 per share were issued in 2000. A purchase price adjustment of $10 million was recorded related to these shares. See Note 2.

Non-employee directors may be granted non-qualified stock options or deferred stock under the 1998 Director Stock Plan. Stock options are granted at the fair market value of Anadarko stock on the date of grant and have a maximum term of ten years from the date of grant. The plan was modified in 2002 to include deferred stock grants.

Unexercised stock options are included in the diluted EPS using the treasury stock method. Information regarding the Company's stock option plans is summarized below:

	2001		2000		1999	
options in millions	**Shares**	**Weighted-Average Exercise Price**	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Shares under option at beginning of year	**14.4**	**$41.28**	8.9	$29.94	8.5	$29.16
Granted	**1.0**	**$58.12**	7.4	$48.80	1.1	$30.39
RME options assumed at merger date	**—**	**$ —**	4.4	$38.93	—	$ —
Exercised	**(0.6)**	**$32.93**	(6.3)	$32.32	(0.7)	$21.05
Surrendered or expired	**(0.2)**	**$59.72**	—	$40.26	—	$35.74
Shares under option at end of year	**14.6**	**$42.49**	14.4	$41.28	8.9	$29.94
Options exercisable at December 31	**7.9**	**$36.26**	6.0	$33.91	5.2	$27.78
Shares available for future grant at end of year	**3.6**		4.8		4.0	
Weighted-average fair value of options granted during the year		**$22.71**		$19.09		$11.20

8. Common Stock and Stock Options (Continued)

The following table summarizes information about the Company's stock options outstanding at December 31, 2001:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Options Outstanding at Year End**	**Weighted-Average Remaining Contractual Life (Years)**	**Weighted-Average Exercise Price**	**Options Exercisable at Year End**	**Weighted-Average Exercise Price**
options in millions					
$14.91-$30.66	2.7	4.4	$26.75	2.7	$26.75
$31.03-$48.44	3.4	5.3	$35.73	3.3	$35.55
$48.53-$48.53	7.1	5.4	$48.53	1.5	$48.53
$48.97-$71.49	1.4	5.9	$58.62	0.4	$58.78
Total	14.6	5.2	$42.49	7.9	$36.26

The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

	2001	2000	1999
Expected option life – years	**4.14**	4.35	4.58
Risk-free interest rate	**4.48%**	6.10%	5.51%
Dividend yield	**0.46%**	0.50%	0.56%
Volatility	**43.79%**	39.17%	35.82%

SFAS No. 123, "Accounting for Stock-based Compensation," defines a fair value method of accounting for an employee stock option or similar equity instrument. SFAS No. 123 allows an entity to continue to measure compensation costs for these plans using Accounting Principles Board (APB) Opinion No. 25 and related interpretations. Anadarko has elected to continue using APB No. 25 for accounting for employee stock compensation plans. Accordingly, no compensation expense is recognized for stock options granted with an exercise price equal to the market value of Anadarko stock on the date of grant. If compensation expense for the Company's stock option plans had been determined using the fair-value method in SFAS No. 123, the Company's net income and EPS would have been as shown in the pro forma amounts below:

millions except per share amounts		**2001**	2000	1999
Net income (loss) available to common stockholders before cumulative effect of change in accounting principle	As reported	**$ (183)**	$ 813	$ 32
	Pro forma	**$ (225)**	$ 776	$ 21
Basic EPS	As reported	**$(0.73)**	$4.42	$ 0.25
	Pro forma	**$(0.90)**	$4.22	$ 0.17
Diluted EPS	As reported	**$(0.73)**	$4.25	$ 0.25
	Pro forma	**$(0.90)**	$4.05	$ 0.17

8. Common Stock and Stock Options (Continued)

The reconciliation between basic and diluted EPS is as follows:

millions except per share amounts	**For the Year Ended December 31, 2001**			For the Year Ended December 31, 2000			For the Year Ended December 31, 1999		
	Loss	**Shares**	**Per Share Amount**	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Basic EPS									
Net income (loss) available to common stockholders before change in accounting principle	**$(183)**	**250**	**$(0.73)**	$813	184	$4.42	$32	125	$0.25
Effect of convertible debentures and ZYP-CODES	**—**	**—**		6	7		—	—	
Effect of dilutive stock options and performance-based stock awards	**—**	**—**		—	2		—	1	
Diluted EPS									
Net income (loss) available to common stockholders plus assumed conversion	**$(183)**	**250**	**$(0.73)**	$819	193	$4.25	$32	126	$0.25

For the years ended December 31, 2001, 2000 and 1999, options for 1.2 million, 0.1 million and 4.4 million shares of common stock, respectively, were excluded from the diluted EPS calculation because the options' exercise price was greater than the average market price of common stock for the periods. For the year ended December 31, 2001, put options for 2 million shares of common stock were excluded because the put options' exercise price was less than the average market price of common stock for the period. For the year ended December 31, 2001, there were 15.9 million potential common shares related to outstanding stock options, convertible debentures and ZYP-CODES that were excluded from the computation of diluted EPS because they had an anti-dilutive effect.

9. Statement of Cash Flows Supplemental Information

The amounts of cash paid (received) for interest (net of amounts capitalized) and income taxes are as follows:

millions	**2001**	2000	1999
Interest	**$ 96**	$90	$70
Income taxes paid (received)	**$169**	$40	$(1)

The RME merger transaction was completed through the issuance of common stock, which was a non-cash transaction that was not reflected in the statement of cash flows. See Note 2. The $53 million of acquisition costs for 2000 reflected in Cash Flow from Investing Activities in the consolidated statement of cash flows represents capitalized merger costs in connection with the RME merger of $147 million, less the cash acquired on the date of the RME merger of $94 million.

10. Transactions With Related Parties and Major Customers

Anadarko has a Production Sharing Agreement (PSA) with **SONATRACH,** the national oil and gas enterprise of Algeria. **SONATRACH** has owned the Company's common stock since 1986 and at year-end 2001 was the beneficial owner of 5% of Anadarko's outstanding common stock. The PSA gives Anadarko the right to develop and produce liquid hydrocarbons in Algeria, subject to the sharing of production with **SONATRACH.** Anadarko has two partners in the PSA. Approximately $10 million, $10 million and $15 million was paid to **SONATRACH** in 2001, 2000 and 1999, respectively, for charges related to oil

10. Transactions With Related Parties and Major Customers (Continued)

purchases, transportation of oil, well testing services, reservoir studies, laboratory services and equipment usage. During 2001, 2000 and 1999, $7 million, $6 million and $21 million, respectively, was received and $7 million was included in accounts payable and $12 million was included in accounts receivable as of December 31, 2001 and 2000, respectively, from **SONATRACH** for joint interest billings of development costs in Algeria under the PSA. During 2000, Anadarko and **SONATRACH** formed an Algeria non-profit company, Groupement Berkine, to carry out their joint operating activities under the PSA. **SONATRACH** and Anadarko fund the expenditures incurred by Groupement Berkine according to their participating interests under the PSA.

In 2001, Anadarko and its partners signed an amendment to the PSA with **SONATRACH,** which allows exploration to resume on Blocks 404, 208 and 211 in areas outside of the exploitation license boundaries encompassing the previous discoveries. Under the terms of the new three-phase exploration program, Anadarko and its partners will spend a minimum of $55 million and expect to drill exploration wells beginning in 2002.

Anadarko also signed an exploration license with **SONATRACH** for Block 406b at Algeria's licensing round in 2001, in which the Company has a 100% interest. The license has a three-year initial term. A work program commitment includes seismic acquisition and one exploration well.

Anadarko and partners have two Engineering, Procurement and Construction (EPC) contracts to build oil production facilities in Algeria with Brown & Root-Condor, a company jointly owned by Brown & Root and affiliates of **SONATRACH.** For the years ended December 31, 2000 and 1999, approximately $4 million and $43 million, respectively, was paid to Brown & Root-Condor under the EPC contracts. No amounts were paid to Brown & Root-Condor under the EPC contracts in 2001.

Political unrest continues in Algeria. Anadarko is closely monitoring the situation and has taken reasonable and prudent steps to ensure the safety of employees and the security of its facilities in the remote regions of the Sahara Desert. Anadarko is presently unable to predict with certainty any effect the current situation may have on activity planned for 2002 and beyond. However, the situation has not had any material effect on the Company's operations to date. The Company's activities in Algeria also are subject to the general risks associated with all foreign operations.

Anadarko recognized revenues of $12 million in 2001 for cumulative preferred dividends declared by OCI Wyoming Co., an equity affiliate. Anadarko owns a 20% common stock interest in OCI Wyoming Co. along with 100% of the cumulative preferred stock. The amount recorded to income in 2001 was for dividends in arrears for the period 1999 through 2001.

The Company's natural gas is sold to interstate and intrastate gas pipelines, direct end-users, industrial users, local distribution companies and gas marketers. Crude oil and condensate are sold to marketers, gatherers and refiners. NGLs are sold to direct end-users, refiners and marketers. These purchasers are located in the United States, Canada, England, Mexico, Italy and Switzerland. The majority of the Company's receivables are paid within two months following the month of purchase.

The Company generally performs a credit analysis of customers prior to making any sales to new customers or increasing credit for existing customers. Based upon this credit analysis, the Company may require a standby letter of credit or a financial guarantee. As of December 31, 2001 and 2000, accounts receivable are shown net of allowance for doubtful accounts of $44 million and $39 million, respectively.

In 2001, sales to Duke Energy and affiliates (Duke Energy) were $1.45 billion, which accounted for 17% of the Company's total 2001 revenues. In 2000, sales to Duke Energy were $1.01 billion, which accounted for 18% of the Company's total 2000 revenues. In 1999, sales to CoEnergy Trading Co. were $181 million, which accounted for 11% of the Company's total 1999 revenues.

11. Segment and Geographic Information

Anadarko's primary business segments are vertically integrated business units that are principally within the oil and gas industry. These segments are managed separately because of their unique technology, marketing and distribution requirements. The Company's three segments are upstream oil and gas activities, downstream marketing activities and minerals activities. The oil and gas exploration and production segment finds and produces natural gas, crude oil, condensate and NGLs. The marketing segment is responsible for selling most of Anadarko's natural gas production as well as volumes of gas, oil and NGLs purchased from third parties. The minerals segment finds and produces minerals in several coal, trona (natural soda ash) and industrial mineral mines. The segment shown as All Other includes other smaller operating units, corporate activities, financing activities and intercompany eliminations.

The Company's accounting policies for segments are the same as those described in the summary of accounting policies. Management evaluates segment performance based on profit or loss from operations before income taxes and various other factors. Transfers between segments are accounted for at market value.

The following table illustrates information related to Anadarko's business segments:

millions	Oil and Gas Exploration and Production	Marketing	Minerals	All Other	Total
2001					
Revenues	**$ 3,048**	**$5,256**	**$ 57**	**$ 8**	**$ 8,369**
Intersegment revenues	**1,480**	**17**	**—**	**(1,497)**	**—**
Total revenues	**4,528**	**5,273**	**57**	**(1,489)**	**8,369**
Depreciation, depletion and amortization	**1,110**	**12**	**4**	**28**	**1,154**
Impairments related to oil and gas properties	**2,546**	**—**	**—**	**—**	**2,546**
Other costs and expenses	**950**	**5,246**	**4**	**(1,213)**	**4,987**
Total costs and expenses	**4,606**	**5,258**	**8**	**(1,185)**	**8,687**
Other (income) expense	**—**	**(91)**	**—**	**163**	**72**
Income (loss) before income taxes	**$ (78)**	**$ 106**	**$ 49**	**$ (467)**	**$ (390)**
Net properties and equipment	**$11,765**	**$ 253**	**$1,206**	**$ 413**	**$13,637**
Capital expenditures	**$ 3,072**	**$ 66**	**$ —**	**$ 178**	**$ 3,316**
2000					
Revenues	$ 1,869	$3,571	$ 52	$ 8	$ 5,500
Intersegment revenues	934	164	—	(1,098)	—
Total revenues	2,803	3,735	52	(1,090)	5,500
Depreciation, depletion and amortization	570	8	2	13	593
Impairments related to oil and gas properties	50	—	—	—	50
Other costs and expenses	575	3,791	2	(930)	3,438
Total costs and expenses	1,195	3,799	4	(917)	4,081
Other (income) expense	—	(174)	—	167	(7)
Income (loss) before income taxes	$ 1,608	$ 110	$ 48	$ (340)	$ 1,426
Net properties and equipment	$11,330	$ 166	$1,211	$ 304	$13,011
Capital expenditures	$ 1,630	$ 41	$ —	$ 37	$ 1,708

11. Segment and Geographic Information (Continued)

millions	Oil and Gas Exploration and Production	Marketing	Minerals	All Other	Total
1999					
Revenues	$ 309	$1,395	$ —	$ 2	$ 1,706
Intersegment revenues	379	37	—	(416)	—
Total revenues	688	1,432	—	(414)	1,706
Depreciation, depletion and amortization	196	7	—	15	218
Impairments related to oil and gas properties	24	—	—	—	24
Other costs and expenses	196	1,421	—	(328)	1,289
Total costs and expenses	416	1,428	—	(313)	1,531
Other (income) expense	—	—	—	70	70
Income (loss) before income taxes	$ 272	$ 4	$ —	$ (171)	$ 105
Net properties and equipment	$ 3,490	$ 132	$ —	$ 59	$ 3,681
Capital expenditures	$ 653	$ 20	$ —	$ 7	$ 680

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

millions	**2001**	2000	1999
Revenues			
United States	**$6,647**	$4,649	$1,592
Canada	**1,336**	447	—
Algeria	**195**	271	114
Other International	**191**	133	—
Total	**$8,369**	$5,500	$1,706

millions	**2001**	2000
Net Properties and Equipment		
United States	**$10,072**	$10,131
Canada	**2,010**	1,540
Algeria	**807**	653
Other International	**748**	687
Total	**$13,637**	$13,011

12. Other Taxes

Significant taxes other than income taxes are as follows:

millions	**2001**	2000	1999
Production and severance	**$139**	$ 88	$17
Ad valorem	**85**	28	14
Payroll and other	**23**	12	5
Total	**$247**	$128	$36

13. Other (Income) Expense

Other (income) expense consists of the following:

millions	**2001**	2000	1999
Firm transportation keep-whole contract valuation (See Note 6)	**$(91)**	$(175)	$—
Foreign currency exchange	**29**	7	—
Change in time value options	**(18)**	—	—
Other	**15**	1	(4)
Total	**$(65)**	$(167)	$(4)

14. Income Taxes

Income tax expense, including deferred amounts, is summarized as follows:

millions	**2001**	2000	1999
Current			
Federal	**$ 32**	$ 8	$ 1
State	**5**	3	—
Foreign	**50**	67	1
Total	**87**	78	2
Deferred			
Federal	**(38)**	405	25
State	**(5)**	24	2
Foreign	**(258)**	95	33
Total	**(301)**	524	60
Total	**$(214)**	$602	$62

Total income taxes were different than the amounts computed by applying the statutory income tax rate to income (loss) before income taxes. The sources of these differences are as follows:

millions	**2001**	2000	1999
Income (Loss) Before Income Taxes			
Domestic	**$ 67**	$1,085	$ 46
Foreign	**(457)**	341	59
Total	**$(390)**	$1,426	$105
Statutory tax rate	**35%**	35%	35%
Tax computed at statutory rate	**$(137)**	$ 499	$ 37
Adjustments resulting from:			
State income taxes (net of federal income tax benefit)	**—**	17	1
Oil and gas credits	**(22)**	(13)	(1)
Taxes related to foreign activities (net of federal income tax benefit)	**(51)**	134	22
Reversal of goodwill amortization	**22**	11	—
Effect of change in Canadian income tax rate	**(31)**	—	—
Other — net	**5**	(46)	3
Total income taxes	**$(214)**	$ 602	$ 62
Effective tax rate	**55%**	42%	59%

14. Income Taxes (Continued)

The tax benefit of compensation expense for tax purposes in excess of amounts recognized for financial accounting purposes has been credited directly to stockholders' equity. For 2001, 2000 and 1999, the tax benefit amounted to $6 million, $67 million and $4 million, respectively.

A net tax benefit of $42 million resulting from the Company's restructuring of certain foreign operations in 2000 was recorded to a deferred liability account. An additional net tax benefit of $49 million was recorded to the account during 2001. In addition, a net tax benefit previously recorded to the account in the amount of $152 million was reversed to goodwill in 2001 as a result of the sale of a wholly-owned subsidiary, which was acquired in the RME merger. The resulting balance after considering amortization, a deferred asset, is reflected in the Company's other long-term assets.

Tax expense in the amount of $10 million was recorded directly to goodwill relating to the sale in 2001 of a wholly-owned subsidiary, which was acquired in the RME merger.

The tax effects of temporary differences that give rise to significant portions of the deferred tax liabilities (assets) at December 31, 2001 and 2000 are as follows:

millions	**2001**	2000
Oil and gas exploration and development costs	**$2,797**	$3,090
Mineral operations	**422**	424
Other	**506**	392
Gross noncurrent deferred tax liabilities	**3,725**	3,906
Net operating loss carryforward	**—**	(55)
Alternative minimum tax credit carryforward	**(136)**	(68)
Other	**(169)**	(150)
Gross noncurrent deferred tax assets	**(305)**	(273)
Less valuation allowance	**31**	—
Net noncurrent deferred tax assets	**(274)**	(273)
Net noncurrent deferred tax liabilities	**$3,451**	$3,633
Alternative minimum tax credit carryforward	**$ —**	$ (65)
Gross current deferred tax asset	**$ —**	$ (65)

The net increase in the valuation allowance during 2001 was $31 million. Of this amount, $14 million was recorded to a deferred asset account. Subsequently recognized tax benefits relating to the reversal of the $14 million will be recorded to a deferred asset account.

Tax credit carryforwards at December 31, 2001, which are available for future utilization on federal income tax returns, are as follows:

millions	**Amount**	**Expiration**
Alternative minimum tax credit	**$136**	Unlimited
General business tax credit	**$ 32**	2006-2021

15. Lease Commitments

The Company has various commitments under non-cancelable operating lease agreements for buildings, facilities and equipment, the majority of which expire at various dates through 2016. The Company also maintains a capital lease for certain furniture and office walls, which were sold but the liability was retained. The majority of the operating leases are expected to be renewed or replaced as they expire. At December 31, 2001, future minimum lease payments and receipts due under operating and capital leases are as follows:

millions	Capital Leases	Operating Leases	Operating Sublease Income
2002	$ 3	$ 72	$ (30)
2003	3	69	(29)
2004	6	66	(6)
2005	1	54	(5)
2006	—	51	(5)
Later years	—	263	(25)
Total future minimum lease payments	13	$575	$(100)
Less: amounts representing interest	(1)		
Present value of minimum capital lease obligations	12		
Less: short-term portion of capital lease obligations	(3)		
Long-term portion of capital lease obligations	$ 9		

Total rental expense, net of sublease income, amounted to $43 million, $48 million and $33 million in 2001, 2000 and 1999, respectively. Capital leases included in fixed assets were zero and $15 million at December 31, 2001 and 2000, respectively.

As a result of the RME merger, the Company recorded a provision for certain operating lease obligations in excess of expected sublease income. The provision for these operating lease obligations was $24 million as of December 31, 2000. In 2001, the Company entered into an agreement under which a third party assumed the Company's full liability under certain RME lease agreements. Therefore, these RME lease agreements are not included in the operating lease obligations shown above.

Synthetic Leases In November 1999, Anadarko entered into a build-to-suit lease arrangement for its corporate office building in The Woodlands, Texas. The development and acquisition of the property was financed by a special purpose entity (SPE) sponsored by a financial institution. The lease balance to be funded under this arrangement will not exceed $185 million. The SPE is not consolidated in the Company's financial statements and, based on the initial terms of the agreement, the Company has accounted for this arrangement as an operating lease in accordance with SFAS No. 13, "Accounting for Leases."

The initial lease term is five years, with up to seven one-year renewal options. Monthly lease payments are based on the London interbank borrowing rate applied against the lease balance and are expected to begin in 2002. Future minimum lease payments under this lease are included in the table above. The lease contains various covenants including covenants regarding the Company's financial condition. Default under the lease, including violation of these covenants, could require the Company to purchase the facility for a specified amount, which approximates the lessor's original cost ($123 million funded as of December 31, 2001). As of December 31, 2001, the Company was in compliance with these covenants.

At the end of the lease term, the Company has an option to either purchase the facility for the purchase option amount of the lease balance plus any outstanding lease payments or to assist the SPE in the sale of the property. The Company has provided a residual value guarantee for any deficiency if the property is sold for

15. Lease Commitments (Continued)

less than the sale option amount ($104 million at December 31, 2001). In addition, the Company is entitled to any proceeds from a sale of the property in excess of the purchase option amount.

In December 2000, the Company entered into a lease arrangement for an office building in The Woodlands, Texas. The acquisition of the property was financed by an SPE sponsored by a financial institution. The amount funded was $48 million. The SPE is not consolidated in the Company's financial statements and the Company has accounted for this arrangement as an operating lease in accordance with SFAS No. 13.

The initial lease term is five years. Monthly lease payments, which began in 2001, are based on the London interbank borrowing rate applied against the $48 million lease balance. Future minimum lease payments under this lease are included in the table above. The lease contains various covenants including covenants regarding the Company's financial condition. Default under the lease, including violation of these covenants, could require the Company to purchase the facility for a specified amount, which approximates the lessor's original cost ($48 million). As of December 31, 2001, the Company is in compliance with these covenants.

At the end of the lease term, the Company has an option to either purchase the facility for the purchase option amount of $48 million plus any outstanding lease payments or to assist the SPE in the sale of the property. The Company has provided a residual value guarantee for any deficiency if the property is sold for less than the sale option amount ($39 million at December 31, 2001). In addition, the Company is entitled to any proceeds from a sale of the property in excess of the purchase option amount.

If for either of these leases, the Company determines that it is probable that the expected fair value of the property at the end of the lease term will be less than the purchase option amount, the Company will accrue the expected loss on a straight line basis over the remaining lease term. Currently, management does not believe it is probable that the fair market value of either of these properties will be less than the purchase option amount at the end of the lease term.

In December 2001, the Company signed a letter of intent under which a floating production platform for its Marco Polo discovery in Green Canyon Block 608 of the Gulf of Mexico will be installed. The other partners will construct the platform and processing facilities that upon completion, expected in 2004, will be operated by Anadarko. The proposed agreement provides that Anadarko will dedicate its production from Green Canyon Block 608 and 11 other Green Canyon blocks to the processing facilities. The proposed agreement will require a monthly demand charge of slightly over $2 million for five years beginning at the time of project completion and a processing fee based upon production. Anadarko will be entitled to 25% of the net after tax cash proceeds from these facilities after payout, as defined, is attained. The letter of intent does not contain any purchase options, purchase obligations or value guarantees. The table of future minimum lease payments above does not include any amounts related to this letter of intent.

16. Pension Plans, Other Postretirement Benefits and Employee Savings Plans

Pension Plans and Other Postretirement Benefits The Company has a defined benefit pension plan and supplemental plans which are non-contributory pension plans. The plans of RME were merged with Anadarko's plans in December 2000. The Company also provides certain health care and life insurance benefits for retired employees. Health care benefits are funded by contributions from the Company and the retiree, with the retiree contributions adjusted to match the provisions of the Company's health care plans. The Company's retiree life insurance plan is non-contributory.

16. Pension Plans, Other Postretirement Benefits and Employee Savings Plans (Continued)

The following table sets forth the Company's pension and other postretirement benefits changes in benefit obligation, fair value of plan assets, funded status and amounts recognized in the financial statements as of December 31, 2001 and 2000.

	Pension Benefits		Other Benefits	
millions	**2001**	2000	**2001**	2000
Change in benefit obligation				
Benefit obligation at beginning of year	**$377**	$ 80	**$ 75**	$ 35
Service cost	**11**	8	**3**	2
Interest cost	**27**	15	**5**	4
Plan merger	**—**	277	**—**	39
Plan amendments	**10**	—	**20**	(5)
Actuarial (gain) loss	**18**	12	**25**	2
Foreign currency exchange rate change	**(2)**	—	**—**	—
Benefit payments and settlements	**(24)**	(15)	**(5)**	(2)
Benefit obligation at end of year	**$417**	$377	**$ 123**	$ 75
Change in plan assets				
Fair value of plan assets at beginning of year	**$396**	$ 62	**$ —**	$ —
Actual return on plan assets	**(32)**	20	**—**	—
Plan merger	**—**	329	**—**	—
Employer contributions	**1**	1	**5**	2
Foreign currency exchange rate change	**(3)**	—	**—**	—
Benefit payments	**(24)**	(16)	**(5)**	(2)
Fair value of plan assets at end of year	**$338**	$396	**$ —**	$ —
Funded status of the plan	**$(79)**	$ 19	**$(123)**	$(75)
Unrecognized actuarial (gain) loss	**80**	3	**23**	(2)
Unrecognized prior service cost	**8**	(2)	**16**	(4)
Unrecognized initial asset	**(2)**	(3)	**—**	—
Total recognized	**$ 7**	$ 17	**$ (84)**	$(81)
Total recognized amounts in the balance sheet consist of:				
Prepaid benefit cost	**$ 23**	$ 24	**$ —**	$ —
Accrued benefit liability	**(51)**	(11)	**(84)**	(81)
Intangible asset	**31**	4	**—**	—
Other comprehensive expense	**4**	—	**—**	—
Total recognized	**$ 7**	$ 17	**$ (84)**	$(81)

Following are the weighted-average assumptions used by the Company in determining the accumulated pension and postretirement benefit obligations as of December 31, 2001 and 2000:

	Pension Benefits		Other Benefits	
percent	**2001**	2000	**2001**	2000
Discount rate	**7.25%**	7.5%	**7.25%**	7.5%
Long-term rate of return on plan assets	**9.0%**	7.5% to 8.0%	**n/a**	n/a
Rates of increase in compensation levels	**5.0%**	5.0% to 5.5%	**5.0%**	5.0%

16. Pension Plans, Other Postretirement Benefits and Employee Savings Plans (Continued)

For measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2001. The rate was assumed to decrease gradually to 5% in 2006 and later years.

	Pension Benefits			Other Benefits		
millions	**2001**	2000	1999	**2001**	2000	1999
Components of net periodic benefit cost						
Service cost	**$ 11**	$ 8	$ 7	**$ 3**	$ 2	$ 2
Interest cost	**27**	15	6	**6**	4	3
Expected return on plan assets	**(28)**	(13)	(5)	**—**	—	—
Amortization values and deferrals	**1**	—	—	**(1)**	(1)	—
Net periodic benefit cost	**$ 11**	$ 10	$ 8	**$ 8**	$ 5	$ 5

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plan with accumulated benefit obligations in excess of plan assets were $393 million, $344 million and $297 million, respectively, as of December 31, 2001, and $32 million, $29 million and $0, respectively, as of December 31, 2000. The Company's benefit obligation under the unfunded pension plans are secured by the Anadarko Petroleum Corporation Executives and Directors Benefits Trust. See Note 8.

The assumed health care cost trend rate has a significant effect on the amounts reported for the health care plan. A 1% change in the assumed health care cost trend rate would have the following effects:

millions	1% Increase	1% Decrease
Effect on total of service and interest cost components	$ 2	$ (2)
Effect on postretirement benefit obligation	$16	$(14)

Employee Savings Plan The Company has an employee savings plan (ESP), which is a defined contribution plan. The Company matches a portion of employees' contributions with shares of the Company's common stock. Participation in the ESP is voluntary and all regular employees of the Company are eligible to participate. The Company charged to expense plan contributions of $11 million, $7 million and $5 million during 2001, 2000 and 1999, respectively. The 2001 contributions were funded through the Employee Stock Ownership Plan (ESOP).

Employee Stock Ownership Plan Effective July 14, 2000, Anadarko adopted the RME ESOP and the shares in the ESOP were converted to shares of Anadarko common stock. As of July 14, 2000, the ESOP consisted of 1.2 million shares or $74 million of common stock (the ESOP shares) to be used to fund the Company's matching obligation under the RME Thrift Plan. All domestic regular employees of RME were eligible to participate in the ESOP. Effective December 31, 2000, the ESOP was merged into the RME Thrift Plan, which was merged into the Anadarko ESP. Beginning January 2001, the Company began using unallocated ESOP shares for Company matching under the Anadarko ESP.

The ESOP shares, which are held in trust, were originally purchased with the proceeds from a 30-year loan from RME in 1997. These shares were pledged as collateral for the loan. As loan payments are made, shares are released from collateral, based on the proportion of debt service paid. Scheduled principal and interest requirements are funded with dividends paid on the ESOP shares and with cash contributions from the Company. Principal or interest prepayments may be made to ensure that the Company's minimum matching obligation is met.

Shares held by the ESOP are included in the computation of earnings per share as ESOP shares are released from collateral. Releases of ESOP shares will be allocated to participants' accounts and will be charged to compensation expense at the fair market value of the shares on the date of the employer match.

16. Pension Plans, Other Postretirement Benefits and Employee Savings Plans (Continued)

As of December 31, 2001 and 2000, the unallocated shares in the ESOP were 0.9 million and 1.1 million, respectively, and the fair value of unallocated ESOP shares at December 31, 2001 and 2000 was $52 million and $79 million, respectively. In 2000, compensation cost related to the allocation of ESOP shares to participants' accounts, other than expense under the ESP plan, was $2 million. In 2001, no compensation cost related to the allocation of ESOP shares, other than expense under the ESP, was recorded.

17. Contingencies

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 numerous claims by employees of third-party contractors alleging exposure to asbestos and benzene while working at a refinery in Corpus Christi, Texas, which RME sold in segments in 1987 and 1989. 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 of the Company, although results of operations and cash flow could be significantly impacted in the reporting periods in which such matters are resolved. Discussed below are several specific proceedings.

Superfund Presently, six Superfund sites (five federal and one state) are included in the Superfund Reserve.

Operating Industries, Inc. (Federal) — The former municipal industrial landfill, located in Monterey Park, California, was operational between 1948 and 1984. RME was noticed as a Potentially Responsible Party (PRP) in June 1986 for its Wilmington Production Field's and Wilmington Refinery's contributions. The Company has agreed to participate in a settlement with the Environmental Protection Agency (EPA). The Company's estimated share of this settlement is $4.3 million. The settlement and consent decree are undergoing final agency review.

Ekotek (Federal) — The facility in Salt Lake City, Utah operated as a refinery from 1953 until 1978, at which time it was converted to a hazardous waste storage/treatment and petroleum recycling facility. The Utah Department of Environmental Quality issued multiple Notices of Violation to the facility in 1988, resulting in the facility's closing. Bear Creek Uranium Company, an affiliate, was named as a PRP for its contributions of used/waste oils. Remediation of the Ekotek site is nearing completion and no additional funding requests are expected.

Casmalia (Federal) — The Casmalia facility, located in Santa Barbara County, California, is a former Resource Conservation and Recovery Act hazardous waste disposal site. RME was noticed as a PRP in March 1993. RME's waste contribution is attributed to the Wilmington Refinery. Negotiations with the EPA are ongoing. The Company believes its share of the costs will be about $0.1 million.

Geothermal Inc. (State) — The site, located in Middletown, California, was permitted as a Class II surface impoundment facility for geothermal wastes. Sludge from drilling operations and power plant wastes generated at the Geysers Geothermal Field between 1976 and 1987 were transported to the facility for treatment/disposal. The waste material was placed in evaporation ponds and allowed to dry. The resultant solids were buried onsite. Site remediation began in 1984. Anadarko was noticed as a PRP in December 1993. Several remedial methods are currently being evaluated to determine the most effective for addressing site groundwater impacts. The Company believes its share of the costs will be about $0.1 million.

PCB Treatment, Inc. (Federal) — The PCB treatment/disposal site, located in Kansas City, Kansas and Kansas City, Missouri, operated from 1982 until 1986 when regulatory violations forced its closure. RME was noticed as a PRP in October 1998 for contributions attributed to Wilmington Refinery operations.

17. Contingencies (Continued)

PCB impacts are currently limited to the facility structures and surrounding soils. Remedial alternatives are under review. The Company believes its share of the costs will be about $0.1 million.

Summitville Mine (Federal) — RME and Cleveland Cliffs Iron Company conducted exploration activities at the site in Summitville, Colorado between 1967 and 1969. The exploration efforts ceased after the companies determined operations were not commercially viable. Several other companies initiated various exploration efforts at the site until 1984 when Galactic Resources permitted a heap leach gold mine at the site. Galactic filed for bankruptcy in 1992 and the EPA implemented a cleanup response in 1993. RME and Cleveland Cliffs negotiated a settlement with the EPA regarding federal liability at the site that excluded claims for natural resource damages. Recently, RME and Cleveland Cliffs reached a settlement with the State of Colorado regarding state liability at the site that includes natural resource damages. This agreement calls for the payment of $0.8 million (RME's share $0.4 million). This agreement became final upon entry of the Settlement Agreement and Consent Decree by the United States District Court for the District of Colorado on September 30, 2001. RME fulfilled its obligations in October 2001 by payment of $0.4 million to the State of Colorado.

Royalty Litigation During September 2000, the Company was named as a defendant in a case styled *U.S. of America ex rel. Harold E. Wright v. AGIP Company, et al.* (the "Gas Qui Tam case") filed in the U.S. District Court for the Eastern District of Texas, Lufkin Division. This lawsuit generally alleges that the Company and 118 other defendants improperly measured and otherwise undervalued natural gas in connection with a payment of royalties on production from federal and Indian lands. The case has been transferred to the U.S. District Court, Multi-District Litigation Docket pending in Wyoming. Based on the Company's present understanding of the various governmental and False Claims Act proceedings described above, the Company believes that it has substantial defenses to these claims and intends to vigorously assert such defenses. However, if the Company is found to have violated the Civil False Claims Act, the Company could be subject to a variety of sanctions, including treble damages and substantial monetary fines.

A group of royalty owners purporting to represent RME's gas royalty owners in Texas (*Neinast, et al.*) was granted class action certification in December 1999, by the 21st Judicial District Court of Washington County, Texas, in connection with a gas royalty underpayment case against the Company. This certification did not constitute a review by the Court of the merits of the claims being asserted. The royalty owners' pleadings did not specify the damages being claimed, although most recently a demand for damages in the amount of $100 million has been asserted. The Company is of the opinion that the amount of damages at risk is substantially less than the amount demanded by the class action counsel and the Company intends to vigorously assert its defenses. The Company appealed the class certification order. A favorable decision from the Houston Court of Appeals decertified the class. It is anticipated that the royalty owners will now appeal this matter to the Texas Supreme Court.

A class action lawsuit entitled *Gilbert H. Coulter, et al. v. Anadarko Petroleum Corporation* has been certified in the 26th Judicial District Court, Stevens County, Kansas. In this action, the royalty owners contend that royalty was underpaid as a result of the deduction for certain post-production costs in the calculation of royalty. The Company believes that its method of calculating royalty was proper and that its gas was marketable in the condition produced, and thus plaintiffs' claims are without merit. This case was certified as a class action in August 2000 and was tried in February 2002. A decision from the trial court is expected by the end of 2002.

Wyoming Tax Litigation RME filed tax appeals in March 1999 before the Wyoming Board of Equalization, alleging that the Wyoming Department of Revenue's revaluation of RME's crude oil production and natural gas production for the years 1989 through 1995 was erroneous. RME also filed a lawsuit in September 2000 in the First District Court of Laramie County, Wyoming, alleging that Wyoming's valuation statute was impermissibly vague. The Department of Revenue revalued RME's crude oil production based upon prices in

17. Contingencies (Continued)

Cushing, Oklahoma, as opposed to the price RME received at the wellhead from its marketing affiliate. The Department of Revenue also sought to revalue RME's natural gas production under a new valuation formula that was approved in a decision the Board of Equalization issued in other litigation while RME's dispute remained pending. RME argued that the price it received for its crude oil production reflected the actual market value of the oil at the wellhead, and that it was neither appropriate nor lawful to value crude oil in Wyoming according to transactions at Cushing. RME also argued that the formula the Department of Revenue previously had used to value natural gas production for many years was the proper formula, and that the new formula approved by the Board of Equalization in the third-party litigation was erroneous. The amount in controversy was approximately $27 million. The Company settled the dispute for $10 million, of which RME already had paid $7 million under protest prior to the merger. As a result of the settlement, the parties have agreed to dismiss the tax appeals and the lawsuit.

CITGO Litigation CITGO Petroleum Corporation's (CITGO) claims arise out of an Asset Purchase and Contribution Agreement dated March 17, 1987 whereby RME's predecessor sold a refinery located in Corpus Christi, Texas, to CITGO's predecessor. After the sale of the refinery, numerous individuals living near the refinery sued CITGO (the Neighborhood Litigation) thereby implicating the Asset Purchase and Contribution Agreement indemnity provision. CITGO and RME eventually entered into a settlement agreement to allocate, on an interim basis, each party's liability for defense and liability cost in that and related litigation. That agreement provides that once the Neighborhood Litigation and certain related claims are resolved, then the parties will determine their final indemnity obligations to each other through binding arbitration. At the present time, RME and CITGO have agreed to defer arbitrating the allocation of responsibility for this liability in order to focus their efforts on a global settlement. Arbitration will resume upon request of either CITGO or RME. In conjunction with this matter, RME sued Continental Insurance for denial of coverage for claims related to this dispute. RME and Continental Insurance settled the insurance coverage litigation which resulted in Continental Insurance paying RME for the claims. Negotiations and discussions with CITGO continue.

Kansas Ad Valorem Tax

General The Natural Gas Policy Act of 1978 allowed a "severance, production or similar" tax to be included as an add-on, over and above the maximum lawful price for natural gas. Based on the Federal Energy Regulatory Commission (FERC) ruling that the Kansas ad valorem tax was such a tax, the Company collected the Kansas ad valorem tax.

Background of PanEnergy Litigation FERC's ruling regarding the ability of producers to collect the Kansas ad valorem tax was appealed to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The Court held in June 1988 that FERC failed to provide a reasoned basis for its findings and remanded the case to FERC.

Ultimately, the D.C. Circuit issued a decision on August 2, 1996 ruling that producers must refund all Kansas ad valorem taxes collected relating to production since October 1983. The Company filed a petition for writ of certiorari with the Supreme Court. That petition was denied on May 12, 1997.

PanEnergy Litigation On May 13, 1997, the Company filed a lawsuit in the Federal District Court for the Southern District of Texas against PanEnergy seeking declaration that pursuant to prior agreements Anadarko is not required to issue refunds to PanEnergy for the principal amount of $14 million (before taxes) and, if the petition for adjustment is denied in its entirety by FERC with respect to PanEnergy refunds, interest in an amount of $38 million (before taxes). The Company also sought from PanEnergy the return of the $1 million (before taxes) charged against income in 1993 and 1994. In October 2000, the U.S. Magistrate issued recommendations concerning motions for summary judgment previously filed by both parties. In essence, the

17. Contingencies (Continued)

Magistrate's recommendation finds that the Company should be responsible for refunds attributable to the time period following August 1, 1985 while Duke Energy (as the successor company to Anadarko Production Company) should be responsible for refunds attributable to the time period before August 1, 1985.

The Company has reached a settlement agreement with PanEnergy that requires the Company to pay $15 million for settlement in full of all matters relating to the refunds of Kansas ad valorem tax reimbursements collected by the Company as first seller from August 1, 1985 through 1988. The settlement agreement was approved by the FERC and paid by Anadarko during 2001. The settlement agreement does not have any impact on the outstanding dispute between the Company and PanEnergy in connection with the refunds that relate to the Cimmaron River System. Anadarko's net income for 2001 included a $15 million charge (before taxes) related to the settlement agreement. Discussions with the Kansas Corporation Commission and PanEnergy to reach a settlement of the Cimmaron River System dispute are ongoing. At this time, it is estimated that a resolution may be reached in the first half of 2002, that may result in a payment by the Company of about $7 million. Accordingly, a provision for $7 million was charged against income in 2001.

Other Litigation Anadarko's net income for 1997 included a $2 million charge (before taxes) related to the Kansas ad valorem tax refunds. This charge reflects all principal and interest which may be due at the conclusion of all regulatory proceedings and litigation to parties other than PanEnergy. The Company is currently unable to predict the final outcome of this matter and no additional provision for liability has been made in the accompanying financial statements.

Lease Agreement The Company, through one of its affiliates, is a party to a lease agreement (base lease) for the leveraged lease financing of the Corpus Christi West Plant Refinery (West Plant) with an initial term expiring December 31, 2003, and successive renewal periods lasting through January 31, 2011. At the conclusion of the initial term of the base lease, any renewal period or January 31, 2011, the Company has the right to purchase the West Plant at the fair market sales value. In connection with the sale by RME of its refining business in 1987 and 1989, the West Plant was subleased to CITGO with sublease payments during the initial term equal to the Company's base lease payments and during any renewal period equal to the lesser of the base lease rental, which will be tied to the annual fair market rental value or a specified maximum amount. Additionally, CITGO has the option under the sublease to purchase the West Plant from the Company at the conclusion of the initial term or any renewal term at the fair market sales value, or on January 31, 2011 at a nominal price. If the fair market rental value of the base lease during any renewal term exceeds CITGO's maximum obligation under the sublease, or if CITGO purchases the West Plant on January 31, 2011 and the fair market sales value of the West Plant is greater than the purchase amount specified in the sublease, the Company will be obligated to pay the excess amounts. The Company is unable at this time to determine the fair market rental value or the fair market sales value of the West Plant, but will at least annually evaluate the potential effect of the obligation.

Guarantees Anadarko is guarantor for certain obligations of its wholly-owned and consolidated subsidiaries, which are included in the consolidated financial statements and notes. In addition, the Company is guarantor for specific financial obligations of two trona mining affiliates. The investments in these entities, which are not consolidated subsidiaries, are accounted for using the equity method. The Company has guaranteed a portion of certain Industrial Revenue Bonds, amounts due under a revolving credit agreement and letters of credit required for environmental surety bonds. The amount the Company would be obligated to pay should the affiliates default on these obligations would be up to $8 million for environmental surety bonds and $35 million for debt.

Enron The recent financial problems of Enron have had no material adverse effect on the Company. As of December 31, 2001, in connection with several physical and financial contracts, the Company had $10 million, net, in accounts payable to Enron North America and $1 million in accounts receivable from other Enron

17. Contingencies (Continued)

affiliates. All contracts have been terminated by Anadarko under the terms of the agreements, and $1 million has been charged to expense in 2001. The Company, through purchase accounting entries for the Berkley acquisition, had recorded market value liabilities on four contracts with Enron which were being amortized over the terms of the contract. Upon termination of these contracts in December 2001, the remaining liability of $12 million was no longer required and was recorded as income in 2001.

Other In connection with a sale of properties, the Company has agreed to indemnify the purchaser for the use of certain currency remeasurement losses utilized by the Company in previously filed tax returns, which are currently being evaluated by the Guatemalan taxing authorities. The Company believes it is probable that these losses will be disallowed by the Guatemalan taxing authorities and will have to be settled with the purchaser in cash. The Company has a $22 million liability recorded for the contingency.

18. Subsequent Events

In February 2002, the Company issued $650 million principal amount of 5⅜% Notes due March 2007. In March 2002, the Company issued $400 million principal amount of 6⅛% Notes due March 2012. The net proceeds from these issuances were used to reduce floating-rate debt and to fund a portion of the ZYP-CODES put to the Company. In March 2002, ZYP-CODES in the amount of $620 million were put to the Company for repayment and were paid in cash.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following table shows summary quarterly financial data for 2001 and 2000.

millions except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2001				
Revenues	**$3,009**	**$2,238**	**$ 1,743**	**$1,379**
Operating income (loss), pretax	**989**[1]	**637**[2]	**(2,160)**[3]	**216**[4]
Net income (loss) before cumulative effect of change in accounting principle	**$ 664**[1]	**$ 402**[2]	**$(1,351)**[3]	**$ 109**[4]
Net income (loss) available to common stockholders before cumulative effect of change in accounting principle	**$ 661**[1]	**$ 401**[2]	**$(1,353)**[3]	**$ 108**[4]
Net income (loss) available to common stockholders	**$ 656**[1]	**$ 401**[2]	**$(1,353)**[3]	**$ 108**[4]
EPS - before cumulative effect of change in accounting principle - basic	**$ 2.64**[1]	**$ 1.60**[2]	**$ (5.41)**[3]	**$ 0.43**[4]
EPS - before cumulative effect of change in accounting principle - diluted	**$ 2.52**[1]	**$ 1.50**[2]	**$ (5.41)**[3]	**$ 0.41**[4]
EPS - basic	**$ 2.62**[1]	**$ 1.60**[2]	**$ (5.41)**[3]	**$ 0.43**[4]
EPS - diluted	**$ 2.50**[1]	**$ 1.50**[2]	**$ (5.41)**[3]	**$ 0.41**[4]
Average number common shares outstanding - basic	**250**	**251**	**250**	**249**
Average number common shares outstanding - diluted	**263**	**268**	**250**	**266**
2000				
Revenues	$ 611	$ 718	$ 1,820	$2,351
Operating income, pretax	119	137	493	670[5]
Net income before cumulative effect of change in accounting principle	$ 50	$ 67	$ 250	$ 457[5]
Net income available to common stockholders before cumulative effect of change in accounting principle	$ 48	$ 64	$ 247	$ 454[5]
Net income available to common stockholders	$ 31	$ 64	$ 247	$ 454[5]
EPS - before cumulative effect of change in accounting principle - basic	$ 0.37	$ 0.50	$ 1.07	$ 1.82[5]
EPS - before cumulative effect of change in accounting principle - diluted	$ 0.37	$ 0.48	$ 1.03	$ 1.75[5]
EPS - basic	$ 0.24	$ 0.50	$ 1.07	$ 1.82[5]
EPS - diluted	$ 0.24	$ 0.48	$ 1.03	$ 1.75[5]
Average number common shares outstanding - basic	128	128	230	249
Average number common shares outstanding - diluted	131	138	241	261

[1] Anadarko's first quarter 2001 operating income includes a non-cash charge of $7 million ($4 million after taxes) related to impairments for exploration activity in Ghana. Anadarko's net income before cumulative effect of change in accounting principle excluding the impairments was $668 million and net income available to common stockholders was $660 million, or $2.52 per common share (diluted).

[2] Anadarko's second quarter 2001 operating income includes a non-cash charge of $8 million ($5 million after taxes) related to impairments for exploration activity in the United Kingdom. Anadarko's net income excluding the impairments was $407 million and net income available to common stockholders was $406 million, or $1.52 per common share (diluted).

[3] Anadarko's operating loss for the third quarter 2001 includes a non-cash charge of $2.53 billion ($1.57 billion after taxes) for impairments of the carrying value of proved oil and gas properties primarily in the United States, Canada and Argentina as a result of low oil and gas prices at the end of the quarter. Anadarko's net income excluding the impairments was $215 million and net income available to common stockholders excluding the impairments was $213 million, or $0.81 per common share (diluted).

[4] Anadarko's fourth quarter 2001 operating income includes a non-cash charge of $3 million ($2 million after taxes) related to impairments for exploration activity in the United Kingdom. Anadarko's net income excluding the impairments was $111 million and net income available to common stockholders was $110 million, or $0.42 per common share (diluted).

[5] Anadarko's fourth quarter 2000 operating income includes a non-cash charge of $50 million ($32 million after income taxes) related to impairments for exploration activities in the United Kingdom, Tunisia and other international locations. Anadarko's net income excluding the impairments was $489 million and net income available to common stockholders was $486 million, or $1.87 per common share (diluted).

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

Oil and Gas Exploration and Production Activities

The following is historical revenue and cost information relating to the Company's oil and gas activities.

Costs Excluded

Excluded from amounts subject to amortization as of December 31, 2001 and 2000 are $3.57 billion and $2.90 billion, respectively, of costs associated with unevaluated properties and major development projects. The majority of the evaluation activities are expected to be completed within five to ten years.

Costs Excluded by Year Incurred

	Year Costs Incurred				Excluded Costs at
millions	Prior Years	1999	2000	2001	Dec. 31, 2001
Property acquisition	$29	$21	$1,217	$ 116	$1,383
Exploration	38	28	1,035	816	1,917
Capitalized interest	6	5	70	192	273
Total	$73	$54	$2,322	$1,124	$3,573

Costs Excluded by Country

millions	U.S.	Canada	Algeria	Other International	Total
Property acquisition	$1,334	$ 49	$ —	$ —	$1,383
Exploration	1,200	503	—	214	1,917
Capitalized interest	226	40	—	7	273
Total	$2,760	$ 592	$ —	$221	$3,573

Changes in Costs Excluded by Country

millions	U.S.	Canada	Algeria	Other International	Total
December 31, 1999	$ 210	$ —	$ 62	$ 51	$ 323
Additional costs incurred in 2000	2,213	453	4	164	2,834
Costs transferred to DD&A pool in 2000	(115)	(41)	(51)	(52)	(259)
December 31, 2000	2,308	412	15	163	2,898
Additional costs incurred in 2001	939	528	1	96	1,564
Costs transferred to DD&A pool in 2001	(487)	(348)	(16)	(38)	(889)
December 31, 2001	$2,760	$ 592	$ —	$221	$3,573

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

Capitalized Costs Related to Oil and Gas Producing Activities

millions	**2001**	2000
United States		
Capitalized		
Unproved properties	**$ 2,760**	$ 2,308
Proved properties	**10,464**	8,667
	13,224	10,975
Accumulated depreciation, depletion and amortization	**5,007**	2,506
Net capitalized costs	**8,217**	8,469
Canada		
Capitalized		
Unproved properties	**592**	412
Proved properties	**2,493**	1,200
	3,085	1,612
Accumulated depreciation, depletion and amortization	**1,086**	77
Net capitalized costs	**1,999**	1,535
Algeria		
Capitalized		
Unproved properties	**—**	15
Proved properties	**907**	704
	907	719
Accumulated depreciation, depletion and amortization	**106**	79
Net capitalized costs	**801**	640
Other International		
Capitalized		
Unproved properties	**221**	163
Proved properties	**610**	562
	831	725
Accumulated depreciation, depletion and amortization	**83**	39
Net capitalized costs	**748**	686
Total		
Capitalized		
Unproved properties	**3,573**	2,898
Proved properties	**14,474**	11,133
	18,047	14,031
Accumulated depreciation, depletion and amortization	**6,282**	2,701
Net capitalized costs	**$11,765**	$11,330

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

Costs Incurred in Oil and Gas Producing Activities

millions	**2001**	2000	1999
United States — Capitalized			
Property acquisition			
Exploration	**$ 156**	$1,897	$ 41
Development	**31**	2,984	50
Exploration	**840**	353	160
Development	**1,196**	777	304
	2,223	6,011	555
Canada — Capitalized			
Property acquisition			
Exploration	**309**	437	—
Development	**835**	1,075	—
Exploration	**223**	16	—
Development	**233**	89	—
	1,600	1,617	—
Algeria — Capitalized			
Property acquisition			
Exploration	**—**	—	1
Exploration	**2**	7	13
Development	**179**	155	49
	181	162	63
Other International — Capitalized			
Property acquisition			
Exploration	**30**	122	1
Development	**67**	532	—
Exploration	**65**	39	34
Development	**136**	33	—
	298	726	35
Total — Capitalized			
Property acquisition			
Exploration	**495**	2,456	43
Development	**933**	4,591	50
Exploration	**1,130**	415	207
Development	**1,744**	1,054	353
	$4,302	$8,516	$653

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

Results of Operations for Producing Activities

The following schedule includes only the revenues from the production and sale of gas, oil, condensate and NGLs. Results of operations from gas, oil and NGLs marketing and gas gathering are excluded. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization (DD&A) 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	**2001**	2000	1999
United States			
Net revenues from production			
Third-party sales of gas, oil, condensate and NGLs	**$2,041**	$1,319	$ 261
Gas and oil sold to consolidated affiliates	**1,344**	748	314
	3,385	2,067	575
Production (lifting) costs	**662**	406	185
Depreciation, depletion and amortization*	**792**	429	178
Impairments related to oil and gas properties	**1,701**	—	—
	230	1,232	212
Income tax expense	**60**	429	75
Results of operations	**$ 170**	$ 803	$ 137
*DD&A rate per net equivalent barrel	**$ 5.54**	$ 5.16	$4.11
Canada			
Net revenues from production			
Third-party sales of gas, oil, condensate and NGLs	**$ 755**	$ 332	$ —
	755	332	—
Production (lifting) costs	**188**	85	—
Depreciation, depletion and amortization*	**225**	76	—
Impairments related to oil and gas properties	**808**	—	—
	(466)	171	—
Income tax expense	**(200)**	68	—
Results of operations	**$ (266)**	$ 103	$ —
*DD&A rate per net equivalent barrel	**$ 6.62**	$ 6.12	$ —
Algeria			
Net revenues from production			
Third-party sales of oil	**$ 59**	$ 85	$ 48
Oil sold to consolidated affiliates	**136**	186	65
	195	271	113
Production (lifting) costs	**21**	23	11
Depreciation, depletion and amortization*	**24**	26	18
	150	222	84
Income tax expense	**57**	137	52
Results of operations	**$ 93**	$ 85	$ 32
*DD&A rate per net equivalent barrel	**$ 3.00**	$ 2.78	$2.96

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

Results of Operations for Producing Activities (Continued)

millions	**2001**	2000	1999
Other International			
Net revenues from production			
Third-party sales of gas, oil, condensate and NGLs	**$ 193**	$ 133	$ —
	193	133	—
Production (lifting) costs	**79**	61	—
Depreciation, depletion and amortization*	**69**	39	—
Impairments related to oil and gas properties	**37**	50	24
	8	(17)	(24)
Income tax expense	**—**	(9)	(9)
Results of operations	**$ 8**	$ (8)	$ (15)
*DD&A rate per net equivalent barrel	**$ 5.31**	$ 5.36	$ n/a
Total			
Net revenues from production			
Third-party sales of gas, oil, condensate and NGLs	**$3,048**	$1,869	$ 309
Gas and oil sold to consolidated affiliates	**1,480**	934	379
	4,528	2,803	688
Production (lifting) costs	**950**	575	196
Depreciation, depletion and amortization*	**1,110**	570	196
Impairments related to oil and gas properties	**2,546**	50	24
	(78)	1,608	272
Income tax expense	**(83)**	625	118
Results of operations	**$ 5**	$ 983	$ 154
*DD&A rate per net equivalent barrel	**$ 5.61**	$ 5.08	$3.97

In July 2000, Anadarko acquired its producing activities in Canada and other international areas as a result of the merger with RME.

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

Oil and Gas Reserves

The following table shows internal estimates prepared by the Company's engineers of proved reserves and proved developed reserves, net of royalty interests, of natural gas, crude oil, condensate and NGLs owned at year-end and changes in proved reserves during the last three years. Volumes for natural gas 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 in millions of barrels of oil equivalent (MMBOE). For this computation, one barrel is the equivalent of six thousand cubic feet of gas. NGLs are included with oil and condensate reserves and the associated shrinkage has been deducted from the gas reserves.

Algerian reserves are shown in accordance with the PSA. The reserves include estimated quantities allocated to Anadarko for recovery of costs and Algerian taxes and Anadarko's net equity share after recovery of such costs.

The Company's reserves increased in 2001 primarily from exploration and development drilling and the Berkley and Gulfstream acquisitions, offset in part by production, divestitures and downward revisions to prior estimates due to low year-end prices. The Company's reserves increased in 2000 primarily from the merger transaction with RME, exploration and development drilling, improved recovery and high gas prices at year-end 2000 compared to year-end 1999. Anadarko's reserves increased in 1999 primarily due to exploration and development drilling and due to significantly higher crude oil and slightly higher natural gas prices at year-end 1999 compared to year-end 1998.

The Company emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data as well as production performance data. These estimates are reviewed and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in assumptions based on, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to uneconomic conditions.

Oil and Gas Reserves (Continued)

	Natural Gas (Bcf)				Oil, Condensate and NGLs (MMBbls)				
	U.S.	Canada	Other Int'l	Total	U.S.	Canada	Algeria	Other Int'l	Total
Proved Reserves									
December 31, 1998	2,647	—	—	2,647	249	—	245	—	494
Revisions of prior estimates	(188)	—	—	(188)	40	—	—	—	40
Extensions, discoveries and other additions	112	—	—	112	1	—	73	—	74
Improved recovery	34	—	—	34	10	—	—	—	10
Purchases in place	99	—	—	99	1	—	—	—	1
Sales in place	(27)	—	—	(27)	(2)	—	(23)	—	(25)
Production	(170)	—	—	(170)	(15)	—	(6)	—	(21)
December 31, 1999	2,507	—	—	2,507	284	—	289	—	573
Revisions of prior estimates	102	(30)	(5)	67	23	(5)	—	6	24
Extensions, discoveries and other additions	665	15	—	680	8	3	84	—	95
Improved recovery	30	—	—	30	9	—	—	—	9
Purchases in place	2,253	910	33	3,196	161	85	—	147	393
Sales in place	—	(2)	—	(2)	—	—	—	(1)	(1)
Production	(338)	(46)	(1)	(385)	(27)	(4)	(9)	(7)	(47)
December 31, 2000	5,219	847	27	6,093	458	79	364	145	1,046
Revisions of prior estimates	(172)	(17)	—	(189)	(23)	(3)	(12)	15	(23)
Extensions, discoveries and other additions	1,186	171	—	1,357	91	8	44	30	173
Improved recovery	(9)	2	—	(7)	(5)	9	—	—	4
Purchases in place	2	407	146	555	1	30	—	33	64
Sales in place	(5)	(48)	(26)	(79)	(1)	(1)	—	(45)	(47)
Production	(573)	(121)	(1)	(695)	(48)	(14)	(9)	(14)	(85)
December 31, 2001	5,648	1,241	146	7,035	473	108	387	164	1,132
Proved Developed Reserves									
December 31, 1998	1,640	—	—	1,640	120	—	44	—	164
December 31, 1999	1,672	—	—	1,672	134	—	61	—	195
December 31, 2000	4,424	720	16	5,160	355	59	98	85	597
December 31, 2001	4,247	1,028	—	5,275	321	79	154	72	626

Oil and Gas Reserves (Continued)

	Total (MMBOE)				
	U.S.	Canada	Algeria	Other Int'l	Total
Proved Reserves					
December 31, 1998	690	—	245	—	935
Revisions of prior estimates	9	—	—	—	9
Extensions, discoveries and other additions	19	—	73	—	92
Improved recovery	16	—	—	—	16
Purchases in place	18	—	—	—	18
Sales in place	(6)	—	(23)	—	(29)
Production	(44)	—	(6)	—	(50)
December 31, 1999	702	—	289	—	991
Revisions of prior estimates	39	(10)	—	6	35
Extensions, discoveries and other additions	118	6	84	—	208
Improved recovery	14	—	—	—	14
Purchases in place	537	237	—	152	926
Sales in place	—	—	—	(1)	(1)
Production	(83)	(13)	(9)	(7)	(112)
December 31, 2000	1,327	220	364	150	2,061
Revisions of prior estimates	(52)	(6)	(12)	15	(55)
Extensions, discoveries and other additions	290	36	44	30	400
Improved recovery	(6)	9	—	—	3
Purchases in place	1	99	—	57	157
Sales in place	(1)	(9)	—	(50)	(60)
Production	(144)	(34)	(9)	(14)	(201)
December 31, 2001	1,415	315	387	188	2,305
Proved Developed Reserves					
December 31, 1998	393	—	44	—	437
December 31, 1999	412	—	61	—	473
December 31, 2000	1,092	179	98	88	1,457
December 31, 2001	1,029	250	154	72	1,505

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

Discounted Future Net Cash Flows

Estimates of future net cash flows from proved reserves of gas, oil, condensate and NGLs were made in accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." The amounts were prepared by the Company's engineers and are shown in the following table. The estimates are based on prices at year-end. Gas prices are escalated only for fixed and determinable amounts under provisions in some contracts. Estimated future cash inflows are reduced by estimated future development and production costs based on year-end cost levels, assuming continuation of existing economic conditions, and by estimated future income tax expense. 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.

At December 31, 2001, the present value (discounted at 10%) of future net revenues from Anadarko's proved reserves was $11.54 billion, before income taxes, and $8.03 billion, after income taxes, (stated in accordance with the regulations of the SEC and the Financial Accounting Standards Board). The after income taxes decrease of $13.37 billion or 62% in 2001 compared to 2000 is primarily due to significantly lower natural gas and crude oil prices at year-end 2001, partially offset by additions of proved reserves related to successful drilling worldwide and the Berkley and Gulfstream acquisitions.

The present value of future net revenues does not purport to be an estimate of the fair market 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 gas. Significant changes in estimated reserve volumes or commodity prices could have a material effect on the Company's consolidated financial statements.

Under the full cost method of accounting, a non-cash charge to earnings related to the carrying value of the Company's oil and gas properties on a country-by-country basis may be required when prices are low. Whether the Company will be required to take such a charge depends on the prices for crude oil and natural gas at the end of any quarter, as well as the effect of both capital expenditures and changes to proved reserves during that quarter. If a non-cash charge were required, it would reduce earnings for the period and result in lower DD&A expense in future periods.

As a result of low oil and gas prices at September 30, 2001, Anadarko's capitalized costs of oil and gas properties in the United States, Canada and Argentina exceeded the ceiling limitation, and the Company recorded a $2.53 billion ($1.57 billion after taxes) non-cash write-down in the third quarter of 2001. The pre-tax write-down is reflected as additional accumulated DD&A in the Company's balance sheet.

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

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

millions	**2001**	2000	1999
United States			
Future cash inflows	**$19,890**	$57,027	$11,012
Future production and development costs	**7,831**	9,357	3,232
Future net cash flows before income taxes	**12,059**	47,670	7,780
10% annual discount for estimated timing of cash flows	**5,805**	22,911	3,916
Discounted future net cash flows before income taxes	**6,254**	24,759	3,864
Future income taxes, net of 10% annual discount	**1,764**	8,546	1,070
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**4,490**	16,213	2,794
Canada			
Future cash inflows	**4,325**	8,720	—
Future production and development costs	**1,590**	1,154	—
Future net cash flows before income taxes	**2,735**	7,566	—
10% annual discount for estimated timing of cash flows	**1,030**	3,261	—
Discounted future net cash flows before income taxes	**1,705**	4,305	—
Future income taxes, net of 10% annual discount	**465**	1,880	—
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**1,240**	2,425	—
Algeria			
Future cash inflows	**7,466**	8,410	7,259
Future production and development costs	**1,426**	1,419	1,077
Future net cash flows before income taxes	**6,040**	6,991	6,182
10% annual discount for estimated timing of cash flows	**3,089**	3,807	3,683
Discounted future net cash flows before income taxes	**2,951**	3,184	2,499
Future income taxes, net of 10% annual discount	**1,109**	1,108	911
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**1,842**	2,076	1,588
Other International			
Future cash inflows	**2,242**	2,631	—
Future production and development costs	**1,049**	1,031	—
Future net cash flows before income taxes	**1,193**	1,600	—
10% annual discount for estimated timing of cash flows	**562**	705	—
Discounted future net cash flows before income taxes	**631**	895	—
Future income taxes, net of 10% annual discount	**172**	204	—
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**459**	691	—
Total			
Future cash inflows	**33,923**	76,788	18,271
Future production and development costs	**11,896**	12,961	4,309
Future net cash flows before income taxes	**22,027**	63,827	13,962
10% annual discount for estimated timing of cash flows	**10,486**	30,684	7,599
Discounted future net cash flows before income taxes	**11,541**	33,143	6,363
Future income taxes, net of 10% annual discount	**3,510**	11,738	1,981
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	**$ 8,031**	$21,405	$ 4,382

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

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

millions	**2001**	2000	1999
United States			
Beginning of year	**$ 16,213**	$ 2,794	$ 1,796
Sales and transfers of oil and gas produced, net of production costs	**(2,724)**	(1,661)	(390)
Net changes in prices and development and production costs	**(19,126)**	7,437	1,451
Extensions, discoveries, additions and improved recovery, less related costs	**624**	2,719	(90)
Development costs incurred during the period	**337**	126	30
Revisions of previous quantity estimates	**(453)**	114	175
Purchases of minerals in place	**17**	11,841	52
Sales of minerals in place	**(5)**	(1)	(22)
Accretion of discount	**2,476**	386	249
Net change in income taxes	**6,782**	(7,476)	(372)
Other	**349**	(66)	(85)
End of year	**4,490**	16,213	2,794
Canada			
Beginning of year	**2,425**	—	—
Sales and transfers of oil and gas produced, net of production costs	**(567)**	(247)	—
Net changes in prices and development and production costs	**(3,317)**	—	—
Extensions, discoveries, additions and improved recovery, less related costs	**279**	101	—
Development costs incurred during the period	**101**	—	—
Revisions of previous quantity estimates	**(38)**	(165)	—
Purchases of minerals in place	**593**	4,568	—
Sales of minerals in place	**(56)**	—	—
Accretion of discount	**431**	—	—
Net change in income taxes	**1,415**	(1,880)	—
Other	**(26)**	48	—
End of year	**1,240**	2,425	—
Algeria			
Beginning of year	**2,076**	1,588	426
Sales and transfers of oil produced, net of production costs	**(174)**	(248)	(102)
Net changes in prices and development and production costs	**(554)**	(330)	1,774
Extensions, discoveries, additions and improved recovery, less related costs	**56**	901	210
Development costs incurred during the period	**164**	135	38
Sales of minerals in place	**—**	—	(85)
Accretion of discount	**318**	250	64
Net change in income taxes	**(1)**	(197)	(697)
Other	**(43)**	(23)	(40)
End of year	**$ 1,842**	$ 2,076	$ 1,588

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

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

millions	**2001**	2000	1999
Other International			
Beginning of year	**$ 691**	$ —	$ —
Sales and transfers of oil and gas produced, net of production costs	**(113)**	(72)	—
Net changes in prices and development and production costs	**(370)**	—	—
Extensions, discoveries, additions and improved recovery, less related costs	**109**	—	—
Development costs incurred during the period	**87**	—	—
Revisions of previous quantity estimates	**75**	—	—
Purchases of minerals in place	**188**	967	—
Sales of minerals in place	**(199)**	—	—
Accretion of discount	**90**	—	—
Net change in income taxes	**32**	(204)	—
Other	**(131)**	—	—
End of year	**459**	691	—
Total			
Beginning of year	**21,405**	4,382	2,222
Sales and transfers of oil and gas produced, net of production costs	**(3,578)**	(2,228)	(492)
Net changes in prices and development and production costs	**(23,367)**	7,107	3,225
Extensions, discoveries, additions and improved recovery, less related costs	**1,068**	3,721	120
Development costs incurred during the period	**689**	261	68
Revisions of previous quantity estimates	**(416)**	(51)	175
Purchases of minerals in place	**798**	17,376	52
Sales of minerals in place	**(260)**	(1)	(107)
Accretion of discount	**3,315**	636	313
Net change in income taxes	**8,228**	(9,757)	(1,069)
Other	**149**	(41)	(125)
End of year	**$ 8,031**	$21,405	$ 4,382

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

See *Anadarko Board of Directors* and *Section 16(a) Beneficial Ownership Reporting Compliance* in the Anadarko Petroleum Corporation Proxy Statement, dated March 25, 2002 (Proxy Statement), which is incorporated herein by reference.

See list of *Executive Officers of the Registrant* appearing under Item 4 of this Form 10-K.

Item 11. Executive Compensation

See *Anadarko Board of Directors — Director Compensation* and *Compensation and Benefits Committee Report on 2001 Executive Compensation* in the Proxy Statement, which is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

See *Stock Ownership* in the Proxy Statement, which is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

See *Transactions with Management* in the Proxy Statement, which is incorporated herein by reference.

PART IV

Item 14. Exhibits and Reports on Form 8-K

(a) The following documents are filed as a 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 61.

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

Exhibit Number	Description	Originally Filed as Exhibit	File Number
2(a)	Agreement and Plan of Merger dated as of April 2, 2000, among Anadarko, Subcorp and RME	2.1 to Form 8-K dated April 2, 2000	1-8968
3(a)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated August 28, 1986	4(a) to Form S-3 dated May 9, 2001	333-60496
(b)	By-laws of Anadarko Petroleum Corporation, as amended	3(e) to Form 10-Q for quarter ended September 30, 2000	1-8968
(c)	Certificate of Amendment of Anadarko's Restated Certificate of Incorporation	4.1 to Form 8-K dated July 28, 2000	1-8968
4(a)	Certificate of Designation of 5.46% Cumulative Preferred Stock, Series B	4(a) to Form 8-K dated May 6, 1998	1-8968
(b)	Rights Agreement, dated as of October 29, 1998, between Anadarko Petroleum Corporation and The Chase Manhattan Bank	4.1 to Form 8-A dated October 30, 1998	1-8968
(c)	Amendment No. 1 to Rights Agreement, dated as of April 2, 2000 between Anadarko and the Rights Agent	2.4 to Form 8-K dated April 2, 2000	1-8968
Director and Executive Compensation Plans and Arrangements			
10(b)(i)	Director Deferred Compensation Plan of Anadarko Petroleum Corporation, effective January 1, 1987	10(b)(viii) to Form 10-K for year ended December 31, 1986	1-8968
(ii)	Amendment to Anadarko Petroleum Corporation Director Deferred Compensation Plan	10(b)(ii) to Form 10-K for year ended December 31, 1997	1-8968
(iii)	Director Deferred Compensation Agreement between Anadarko Petroleum Corporation and each Director Electing to Participate	19(a)(i) to Form 10-Q for quarter ended March 31, 1987	1-8968
(iv)	First Amendment to Director Deferred Compensation Agreement 1987, 1988, 1989 and 1990 Plan Years	10(b)(iv) to Form 10-K for year ended December 31, 1997	1-8968
(v)	Termination of Director Deferred Compensation Plan of Anadarko Petroleum Corporation, effective July 11, 2000	10(b)(v) to Form 10-K for year ended December 31, 2000	1-8968

Exhibit Number	Description	Originally Filed as Exhibit	File Number
10(b)(vi)	Anadarko Petroleum Corporation 1988 Stock Option Plan for Non-Employee Directors	19(b) to Form 10-Q for quarter ended September 30, 1988	1-8968
(vii)	Anadarko Petroleum Corporation Amended and Restated 1988 Stock Option Plan for Non-Employee Directors	99 — Attachment A to Form 10-K for year ended December 31, 1993	1-8968
(viii)	Amendment to Anadarko Petroleum Corporation 1988 Stock Option Plan for Non-Employee Directors	10(b)(vii) to Form 10-K for year ended December 31, 1997	1-8968
(ix)	Second Amendment to Anadarko Petroleum Corporation 1988 Stock Option Plan for Non-Employee Directors	10(b)(viii) to Form 10-K for year ended December 31, 1997	1-8968
(x)	1998 Director Stock Plan of Anadarko Petroleum Corporation, effective January 30, 1998	99 — Attachment A to Form 10-K for year ended December 31, 1997	1-8968
(xi)	Anadarko Petroleum Corporation and Participating Affiliates and Subsidiaries Annual Override Pool Bonus Plan, as amended October 6, 1986	19(c)(ix) to Form 10-Q for quarter ended September 30, 1986	1-8968
(xii)	Second Amendment to Anadarko Petroleum Corporation and Participating Affiliates and Subsidiaries Annual Override Pool Bonus Plan	10(b)(ii) to Form 10-K for year ended December 31, 1987	1-8968
(xiii)	Restatement of the Anadarko Petroleum Corporation 1987 Stock Option Plan (and Related Agreement)	Post Effective Amendment No. 1 to Forms S-8 and S-3, Anadarko Petroleum Corporation 1987 Stock Option Plan	33-22134
(xiv)	First Amendment to Restatement of the Anadarko Petroleum Corporation 1987 Stock Option Plan	10(b)(xii) to Form 10-K for year ended December 31, 1997	1-8968
(xv)	1993 Stock Incentive Plan	10(b)(xii) to Form 10-K for year ended December 31, 1993	1-8968
(xvi)	First Amendment to Anadarko Petroleum Corporation 1993 Stock Incentive Plans	99 — Attachment A to Form 10-K for year ended December 31, 1996	1-8968
(xvii)	Second Amendment to Anadarko Petroleum Corporation 1993 Stock Incentive Plan	10(b)(xv) to Form 10-K for year ended December 31, 1997	1-8968
(xviii)	Anadarko Petroleum Corporation 1993 Stock Incentive Plan Stock Option Agreement	10(a) to Form 10-Q for quarter ended March 31, 1996	1-8968
(xix)	Form of Anadarko Petroleum Corporation 1993 Stock Incentive Plan Stock Option Agreement	10(b)(xvii) to Form 10-K for year ended December 31, 1997	1-8968
(xx)	Form of Anadarko Petroleum Corporation 1993 Stock Incentive Plan Restricted Stock Agreement	10(b)(xviii) to Form 10-K for year ended December 31, 1997	1-8968

Exhibit Number	Description	Originally Filed as Exhibit	File Number
10(b)(xxi)	Anadarko Petroleum Corporation 1999 Stock Incentive Plan	99 — Attachment A to Form 10-K for year ended December 31, 1998	1-8968
(xxii)	Amendment to 1999 Stock Incentive Plan, as of July 1, 2000	10(b)(xxii) to Form 10-K for year ended December 31, 2000	1-8968
(xxiii)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Stock Option Agreement	10(b)(xxiii) to Form 10-K for year ended December 31, 1999	1-8968
(xxiv)	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	1-8968
(xxv)	Annual Incentive Bonus Plan	10(b)(xiii) to Form 10-K for year ended December 31, 1993	1-8968
(xxvi)	First Amendment to Anadarko Petroleum Corporation Annual Incentive Bonus Plan	99 — Attachment B to Form 10-K for year ended December 31, 1998	1-8968
(xxvii)	Key Employee Change of Control Contract	10(b)(xxii) to Form 10-K for year ended December 31, 1997	1-8968
(xxviii)	First Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract	10(b) to Form 10-Q for quarter ended September 30, 2000	1-8968
(xxix)	Executive Deferred Compensation Plan of Anadarko Petroleum Corporation and Participating Subsidiaries and Affiliates, effective October 1, 1986	10(b)(xii) to Form 10-K for year ended December 31, 1987	1-8968
(xxx)	Executive Deferred Compensation Plan of Anadarko Petroleum Corporation, effective January 1, 1987	10(b)(vi) to Form 10-K for year ended December 31, 1986	1-8968
(xxxi)	Amendment to Anadarko Petroleum Corporation Executive Deferred Compensation Plan	10(b)(xxv) to Form 10-K for year ended December 31, 1997	1-8968
(xxxii)	Executive Deferred Compensation Agreement between Anadarko Petroleum Corporation and each Executive Electing to Participate	19(a)(ii) to Form 10-Q for quarter ended March 31, 1987	1-8968
(xxxiii)	First Amendment to Executive Deferred Compensation Agreement 1987, 1988, 1989 and 1990 Plan Years	10(b)(xxvii) to Form 10-K for year ended December 31, 1997	1-8968
(xxxiv)	Amendments to Executive Deferred Compensation Agreement between Anadarko Petroleum Corporation and each Executive Electing to Participate	10(b)(xv) to Form 10-K for year ended December 31, 1987	1-8968
(xxxv)	Termination of Executive Deferred Compensation Plan of Anadarko Petroleum Corporation, effective July 11, 2000	10(b)(xxxv) to Form 10-K for year ended December 31, 2000	1-8968
(xxxvi)	Anadarko Retirement Restoration Plan, effective January 1, 1995	10(b)(xix) to Form 10-K for year ended December 31, 1995	1-8968

Exhibit Number	Description	Originally Filed as Exhibit	File Number
10(b)(xxxvii)	Anadarko Savings Restoration Plan, effective January 1, 1995	10(b)(xx) to Form 10-K for year ended December 31, 1995	1-8968
(xxxviii)	Amendment to Amended and Restated Anadarko Savings Restoration Plan	10(b)(xxxi) to Form 10-K for year ended December 31, 1997	1-8968
(xxxix)	Plan Agreement for the Management Life Insurance Plan between Anadarko Petroleum Corporation and each Eligible Employee, effective July 1, 1995	10(b)(xxi) to Form 10-K for year ended December 31, 1995	1-8968
(xl)	Anadarko Petroleum Corporation Estate Enhancement Program	10(b)(xxxiv) to Form 10-K for year ended December 31, 1998	1-8968
(xli)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives	10(b)(xxxv) to Form 10-K for year ended December 31, 1998	1-8968
(xlii)	Estate Enhancement Program Agreements effective November 29, 2000	10(b)(xxxxii) to Form 10-K for year ended December 31, 2000	1-8968
(xliii)	Employment Agreement	10(a) to Form 10-Q for quarter ended September 30, 2000	1-8968
*12	Computation of Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Stock Dividends		
*21	List of Significant Subsidiaries		
*23	Consents of Experts and Counsel Consent of KPMG LLP		
*24	Powers of Attorney		
99	Anadarko Petroleum Corporation Proxy Statement, dated March 25, 2002	Filed on March 22, 2002	

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 registrant 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) Reports on Form 8-K

There were no reports filed on Form 8-K during the three months ended December 31, 2001.

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

March 22, 2002

By: MICHAEL E. ROSE
(Michael E. Rose, Executive Vice President, Finance and Chief Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 22, 2002.

Name and Signature	Title
(i) Principal executive officer:*	
JOHN N. SEITZ (John N. Seitz)	President and Chief Executive Officer
(ii) Principal financial officer:*	
MICHAEL E. ROSE (Michael E. Rose)	Executive Vice President, Finance and Chief Financial Officer
(iii) Principal accounting officer:*	
JAMES R. LARSON (James R. Larson)	Vice President and Controller
(iv) Directors:*	

ROBERT J. ALLISON, JR.
CONRAD P. ALBERT
LARRY BARCUS
RONALD BROWN
JAMES L. BRYAN
JOHN R. BUTLER, JR.
PRESTON M. GEREN III
JOHN R. GORDON
GEORGE LINDAHL III
JOHN W. PODUSKA, SR.
JEFF D. SANDEFER
JOHN N. SEITZ

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

By MICHAEL E. ROSE
(Michael E. Rose, Attorney-in-Fact)

EXHIBIT INDEX

(a) The following documents are filed as a 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 61.

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(c)	Amendment No. 1 to Rights Agreement, dated as of April 2, 2000 between Anadarko and the Rights Agent	2.4 to Form 8-K dated April 2, 2000	1-8968
Director and Executive Compensation Plans and Arrangements			
10(b)(i)	Director Deferred Compensation Plan of Anadarko Petroleum Corporation, effective January 1, 1987	10(b)(viii) to Form 10-K for year ended December 31, 1986	1-8968
(ii)	Amendment to Anadarko Petroleum Corporation Director Deferred Compensation Plan	10(b)(ii) to Form 10-K for year ended December 31, 1997	1-8968
(iii)	Director Deferred Compensation Agreement between Anadarko Petroleum Corporation and each Director Electing to Participate	19(a)(i) to Form 10-Q for quarter ended March 31, 1987	1-8968
(iv)	First Amendment to Director Deferred Compensation Agreement 1987, 1988, 1989 and 1990 Plan Years	10(b)(iv) to Form 10-K for year ended December 31, 1997	1-8968
(v)	Termination of Director Deferred Compensation Plan of Anadarko Petroleum Corporation, effective July 11, 2000	10(b)(v) to Form 10-K for year ended December 31, 2000	1-8968
(vi)	Anadarko Petroleum Corporation 1988 Stock Option Plan for Non-Employee Directors	19(b) to Form 10-Q for quarter ended September 30, 1988	1-8968
(vii)	Anadarko Petroleum Corporation Amended and Restated 1988 Stock Option Plan for Non-Employee Directors	99 — Attachment A to Form 10-K for year ended December 31, 1993	1-8968

Exhibit Number	Description	Originally Filed as Exhibit	File Number
10(b)(viii)	Amendment to Anadarko Petroleum Corporation 1988 Stock Option Plan for Non-Employee Directors	10(b)(vii) to Form 10-K for year ended December 31, 1997	1-8968
(ix)	Second Amendment to Anadarko Petroleum Corporation 1988 Stock Option Plan for Non-Employee Directors	10(b)(viii) to Form 10-K for year ended December 31, 1997	1-8968
(x)	1998 Director Stock Plan of Anadarko Petroleum Corporation, effective January 30, 1998	99 — Attachment A to Form 10-K for year ended December 31, 1997	1-8968
(xi)	Anadarko Petroleum Corporation and Participating Affiliates and Subsidiaries Annual Override Pool Bonus Plan, as amended October 6, 1986	19(c)(ix) to Form 10-Q for quarter ended September 30, 1986	1-8968
(xii)	Second Amendment to Anadarko Petroleum Corporation and Participating Affiliates and Subsidiaries Annual Override Pool Bonus Plan	10(b)(ii) to Form 10-K for year ended December 31, 1987	1-8968
(xiii)	Restatement of the Anadarko Petroleum Corporation 1987 Stock Option Plan (and Related Agreement)	Post Effective Amendment No. 1 to Forms S-8 and S-3, Anadarko Petroleum Corporation 1987 Stock Option Plan	33-22134
(xiv)	First Amendment to Restatement of the Anadarko Petroleum Corporation 1987 Stock Option Plan	10(b)(xii) to Form 10-K for year ended December 31, 1997	1-8968
(xv)	1993 Stock Incentive Plan	10(b)(xii) to Form 10-K for year ended December 31, 1993	1-8968
(xvi)	First Amendment to Anadarko Petroleum Corporation 1993 Stock Incentive Plans	99 — Attachment A to Form 10-K for year ended December 31, 1996	1-8968
(xvii)	Second Amendment to Anadarko Petroleum Corporation 1993 Stock Incentive Plan	10(b)(xv) to Form 10-K for year ended December 31, 1997	1-8968
(xviii)	Anadarko Petroleum Corporation 1993 Stock Incentive Plan Stock Option Agreement	10(a) to Form 10-Q for quarter ended March 31, 1996	1-8968
(xix)	Form of Anadarko Petroleum Corporation 1993 Stock Incentive Plan Stock Option Agreement	10(b)(xvii) to Form 10-K for year ended December 31, 1997	1-8968
(xx)	Form of Anadarko Petroleum Corporation 1993 Stock Incentive Plan Restricted Stock Agreement	10(b)(xviii) to Form 10-K for year ended December 31, 1997	1-8968
(xxi)	Anadarko Petroleum Corporation 1999 Stock Incentive Plan	99 — Attachment A to Form 10-K for year ended December 31, 1998	1-8968
(xxii)	Amendment to 1999 Stock Incentive Plan, as of July 1, 2000	10(b)(xxii) to Form 10-K for year ended December 31, 2000	1-8968
(xxiii)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Stock Option Agreement	10(b)(xxiii) to Form 10-K for year ended December 31, 1999	1-8968

Exhibit Number	Description	Originally Filed as Exhibit	File Number
10(b)(xxiv)	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	1-8968
(xxv)	Annual Incentive Bonus Plan	10(b)(xiii) to Form 10-K for year ended December 31, 1993	1-8968
(xxvi)	First Amendment to Anadarko Petroleum Corporation Annual Incentive Bonus Plan	99 — Attachment B to Form 10-K for year ended December 31, 1998	1-8968
(xxvii)	Key Employee Change of Control Contract	10(b)(xxii) to Form 10-K for year ended December 31, 1997	1-8968
(xxviii)	First Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract	10(b) to Form 10-Q for quarter ended September 30, 2000	1-8968
(xxix)	Executive Deferred Compensation Plan of Anadarko Petroleum Corporation and Participating Subsidiaries and Affiliates, effective October 1, 1986	10(b)(xii) to Form 10-K for year ended December 31, 1987	1-8968
(xxx)	Executive Deferred Compensation Plan of Anadarko Petroleum Corporation, effective January 1, 1987	10(b)(vi) to Form 10-K for year ended December 31, 1986	1-8968
(xxxi)	Amendment to Anadarko Petroleum Corporation Executive Deferred Compensation Plan	10(b)(xxv) to Form 10-K for year ended December 31, 1997	1-8968
(xxxii)	Executive Deferred Compensation Agreement between Anadarko Petroleum Corporation and each Executive Electing to Participate	19(a)(ii) to Form 10-Q for quarter ended March 31, 1987	1-8968
(xxxiii)	First Amendment to Executive Deferred Compensation Agreement 1987, 1988, 1989 and 1990 Plan Years	10(b)(xxvii) to Form 10-K for year ended December 31, 1997	1-8968
(xxxiv)	Amendments to Executive Deferred Compensation Agreement between Anadarko Petroleum Corporation and each Executive Electing to Participate	10(b)(xv) to Form 10-K for year ended December 31, 1987	1-8968
(xxxv)	Termination of Executive Deferred Compensation Plan of Anadarko Petroleum Corporation, effective July 11, 2000	10(b)(xxxv) to Form 10-K for year ended December 31, 2000	1-8968
(xxxvi)	Anadarko Retirement Restoration Plan, effective January 1, 1995	10(b)(xix) to Form 10-K for year ended December 31, 1995	1-8968
(xxxvii)	Anadarko Savings Restoration Plan, effective January 1, 1995	10(b)(xx) to Form 10-K for year ended December 31, 1995	1-8968
(xxxviii)	Amendment to Amended and Restated Anadarko Savings Restoration Plan	10(b)(xxxi) to Form 10-K for year ended December 31, 1997	1-8968
(xxxix)	Plan Agreement for the Management Life Insurance Plan between Anadarko Petroleum Corporation and each Eligible Employee, effective July 1, 1995	10(b)(xxi) to Form 10-K for year ended December 31, 1995	1-8968

Exhibit Number	Description	Originally Filed as Exhibit	File Number
10(b)(xl)	Anadarko Petroleum Corporation Estate Enhancement Program	10(b)(xxxiv) to Form 10-K for year ended December 31, 1998	1-8968
(xli)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives	10(b)(xxxv) to Form 10-K for year ended December 31, 1998	1-8968
(xlii)	Estate Enhancement Program Agreements effective November 29, 2000	10(b)(xxxxii) to Form 10-K for year ended December 31, 2000	1-8968
(xliii)	Employment Agreement	10(a) to Form 10-Q for quarter ended September 30, 2000	1-8968
*12	Computation of Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Stock Dividends		
*21	List of Significant Subsidiaries		
*23	Consents of Experts and Counsel Consent of KPMG LLP		
*24	Powers of Attorney		
99	Anadarko Petroleum Corporation Proxy Statement, dated March 25, 2002	Filed on March 22, 2002	

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 registrant 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.