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2004

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 fiscal year ended December 31, 2004

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number 1-2256

EXXON MOBIL CORPORATION

(Exact name of registrant as specified in its charter)

NEW JERSEY	13-5409005
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298
(Address of principal executive offices) (Zip Code)
(972) 444-1000
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, without par value (6,385,358,170 shares outstanding at January 31, 2005)	**New York Stock Exchange**
Registered securities guaranteed by Registrant:	
SeaRiver Maritime Financial Holdings, Inc.	
Twenty-Five Year Debt Securities due October 1, 2011	**New York Stock Exchange**
Exxon Capital Corporation	
Twelve Year 6% Notes due July 1, 2005	**New York Stock Exchange**

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 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 registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ✓

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ✓ No ___

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2004, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $44.41 on the New York Stock Exchange composite tape, was in excess of $288 billion.

Documents Incorporated by Reference:
Proxy Statement for the 2005 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004

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PART I

Item 1. ***Business.***

Exxon Mobil Corporation, formerly named Exxon Corporation, was incorporated in the State of New Jersey in 1882. On November 30, 1999, Mobil Corporation became a wholly-owned subsidiary of Exxon Corporation, and Exxon changed its name to Exxon Mobil Corporation.

Divisions and affiliated companies of ExxonMobil operate or market products in the United States and about 200 other countries and territories. Their principal business is energy, involving exploration for, and production of, crude oil and natural gas, manufacture of petroleum products and transportation and sale of crude oil, natural gas and petroleum products. ExxonMobil is a major manufacturer and marketer of basic petrochemicals, including olefins, aromatics, polyethylene and polypropylene plastics and a wide variety of specialty products. ExxonMobil also has interests in electric power generation facilities. Affiliates of ExxonMobil conduct extensive research programs in support of these businesses.

Exxon Mobil Corporation has several divisions and hundreds of affiliates, many with names that include *ExxonMobil, Exxon, Esso* or *Mobil*. For convenience and simplicity, in this report the terms *ExxonMobil, Exxon, Esso* and *Mobil*, as well as terms like *Corporation, Company, our, we* and *its*, are sometimes used as abbreviated references to specific affiliates or groups of affiliates. The precise meaning depends on the context in question.

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on the air, water and ground. This includes a significant investment in refining technology to manufacture low-sulfur motor fuels and projects to reduce nitrogen oxide and sulfur oxide emissions. ExxonMobil's 2004 worldwide environmental costs for all such preventative and remediation steps were about $2.9 billion, of which $1.1 billion were capital expenditures and $1.8 billion were included in expenses. The total cost for such activities is expected to be about $3.0 billion in 2005 (with capital expenditures representing just over 40 percent of the total) and a similar amount is expected for 2006.

Operating data and industry segment information for the Corporation are contained on pages 75, 76, 88 and 89; information on oil and gas reserves is contained on pages 82 through 85 and information on Company-sponsored research and development activities is contained on page 57 of the Financial Section of this report.

The number of regular employees was 85.9 thousand, 88.3 thousand and 92.5 thousand at years ended 2004, 2003 and 2002, respectively. Regular employees are defined as active executive, management, professional, technical and wage employees who work full time or part time for the Corporation and are covered by the Corporation's benefit plans and programs. Regular employees do not include employees of the company-operated retail sites (CORS). The number of CORS employees was 19.3 thousand, 17.4 thousand and 16.8 thousand at years ended 2004, 2003 and 2002, respectively.

ExxonMobil maintains a website at www.exxonmobil.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available through our website as soon as reasonably practical after we electronically file or furnish the reports to the Securities and Exchange Commission. Also available on the Corporation's website are the Company's Corporate Governance Guidelines and Code of Ethics and Business Conduct, as well as the charters of the audit, compensation and nominating committees of the board of directors. All of these documents are available in print without charge to shareholders who request them. Information on our website is not incorporated into this report.

Factors Affecting Future Results

Competitive Factors: The energy and petrochemical industries are highly competitive. There is competition within the industries and also with other industries in supplying the energy, fuel and chemical needs of industry and individual consumers. The Corporation competes with other firms in the sale or purchase of various goods or services in many national and international markets and employs all methods of competition which are lawful and appropriate for such purposes. A key component of the Corporation's competitive position, particularly given the commodity-based nature of many of its products, is its ability to manage expenses successfully, which requires continuous management focus on reducing unit costs and improving efficiency.

Political Factors: The operations and earnings of the Corporation and its affiliates throughout the world have been, and may in the future be, affected from time to time in varying degree by political instability and by other political developments and laws and regulations, such as forced divestiture of assets; restrictions on production, imports and exports; war or other international conflicts; civil unrest and local security concerns that threaten the safe operation of company facilities; price controls; tax increases and retroactive tax claims; expropriation of property; cancellation of contract rights; and environmental regulations. Both the likelihood of such occurrences and their overall effect upon the Corporation vary greatly from country to country and are not predictable.

Industry and Economic Factors: The operations and earnings of the Corporation and its affiliates throughout the world are affected by local, regional and global events or conditions that affect supply and demand for oil, natural gas, petroleum products, petrochemicals and other ExxonMobil products. These events or conditions are generally not predictable and include, among other things, general economic growth rates and the occurrence of economic recessions; the development of new supply sources; adherence by countries to OPEC quotas; supply disruptions; weather, including seasonal patterns that affect energy demand and severe weather events that can disrupt operations; technological advances, including advances in exploration, production, refining, and petrochemical manufacturing technology and advances in technology relating to energy usage; changes in demographics, including population growth rates and consumer preferences; and the competitiveness of alternative hydrocarbon or other energy sources or product substitutes.

Project Factors: In addition to the factors cited above, the advancement, cost and results of particular ExxonMobil projects depend on the outcome of negotiations with partners, governments, suppliers, customers or others; changes in operating conditions or costs; changes in rates of field decline; and the occurrence of unforeseen technical difficulties. See section 1 of Item 2 of this report for discussion of additional factors affecting future capacity growth and the timing and ultimate recovery of reserves.

Market Risk Factors: See pages 39 and 40 of the Financial Section of this report for discussion of the impact of market risks, inflation and other uncertainties.

Projections, estimates and descriptions of ExxonMobil's plans and objectives included or incorporated in Items 1, 2, 7 and 7A of this report are forward-looking statements. Actual future results, including project completion dates, production rates, capital expenditures, costs and business plans could differ materially due to, among other things, the factors discussed above and elsewhere in this report.

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Item 2. ***Properties.***

Part of the information in response to this item and to the Securities Exchange Act Industry Guide 2 is contained in the Financial Section of this report in Note 9, which note appears on page 59, and on pages 78 through 87.

Information with regard to oil and gas producing activities follows:

1. Net Reserves of Crude Oil and Natural Gas Liquids and Natural Gas at Year-End 2004

Estimated proved reserves are shown on pages 82 through 85 of the Financial Section of this report. No major discovery or other favorable or adverse event has occurred since December 31, 2004, that would cause a significant change in the estimated proved reserves as of that date, with the exception of bitumen prices in western Canada which have increased substantially from December 31. This price increase resulted in the rebooking, in 2005, of approximately 0.5 billion oil-equivalent barrels at the Cold Lake field. For information on the standardized measure of discounted future net cash flows relating to proved oil and gas reserves, see pages 86 and 87 of the Financial Section of this report.

The table below summarizes the oil-equivalent proved reserves in each geographic area for consolidated subsidiaries as detailed on pages 82 through 85 of the Financial Section of this report for the year ended December 31, 2004. The Corporation has reported 2004 proved reserves on the basis of December 31, 2004 prices and costs for the first time. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

	United States	Canada	Europe	Asia Pacific	Africa	Middle East	Other	Total Consolidated
				(millions of barrels)				
Liquids	2,593	627	1,014	601	2,444	49	1,067	8,395
				(billions of cubic feet)				
Natural gas	12,329	1,883	9,185	5,919	771	684	1,072	31,843
				(millions of oil-equivalent barrels)				
Oil-equivalent basis	4,648	941	2,545	1,587	2,572	163	1,246	13,702

Additional detail on developed and undeveloped oil-equivalent proved reserves is shown in the table below.

	Year-End 2004		Year-End 2003	
	Developed	Undeveloped	Developed	Undeveloped
	(millions of oil-equivalent barrels)			
Consolidated Subsidiaries				
United States	3,726	922	3,934	737
Canada	836	105	1,077	507
Europe	1,942	603	2,004	871
Asia Pacific	1,132	455	1,433	465
Africa	1,164	1,408	1,133	1,706
Middle East	11	152	20	190
Caspian region	34	606	33	726
South America	176	430	187	432
Total	9,021	4,681	9,821	5,634
Equity Companies				
United States	367	59	383	68
Europe	1,649	627	1,311	993
Middle East	1,404	2,007	1,064	712
Caspian region	740	399	632	585
Total	4,160	3,092	3,390	2,358

In the preceding reserves information, and in the reserves tables on pages 82 through 85 of the Financial Section of this report, consolidated subsidiary and equity company reserves are reported separately. However, the Corporation operates its business with the same views of equity company reserves as it has for reserves from consolidated subsidiaries.

The Corporation's overall volume capacity outlook, based on projects coming on stream as anticipated, is for production capacity increases to average 3 percent annually through 2010. However, actual volume increases will vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, price effects on production sharing contracts and other factors as described under the heading "Factors Affecting Future Results" in Item 1 of this report.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations and extrapolations of well information such as flow rates and reservoir pressure declines. In certain deepwater fields, proved reserves are recorded in a limited number of cases before flow tests are conducted because of the safety and cost implications of conducting the tests. In those situations, other industry accepted analyses are used such as information from well logs, a thorough pressure and fluid sampling program, conventional core data obtained across the entire reservoir interval and nearby analog data. Historically, proved reserves recorded using these methods have been immaterial when compared to the Corporation's total proved reserves and have also been validated by subsequent flow tests or actual production levels. Furthermore, the Corporation only records proved reserves for projects which have received significant funding commitments by management made toward the development of the reserves. Although the Corporation is reasonably certain that proved reserves will be produced, the timing and ultimate recovery can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in projections of long term oil and gas price levels.

2. Estimates of Total Net Proved Oil and Gas Reserves Filed with Other Federal Agencies

During 2004, ExxonMobil filed proved reserves estimates with the U.S. Department of Energy on Forms EIA-23 and EIA-28. The information on Form EIA-28 is presented on the same basis as the registrant's Annual Report on Form 10-K for 2003, which shows ExxonMobil's net interests in all liquids and gas reserve volumes and changes thereto from both ExxonMobil-operated properties and properties operated by others. The data on Form EIA-23, although consistent with the data on Form EIA-28, is presented on a different basis, and includes 100 percent of the oil and gas volumes from ExxonMobil-operated properties only, regardless of the company's net interest. In addition, Form EIA-23 information does not include gas plant liquids. The difference between the oil reserves reported on EIA-23 and those reported in the registrant's Annual Report on Form 10-K for 2003 exceeds five percent. The difference in gas reserves did not exceed five percent.

3. Average Sales Prices and Production Costs per Unit of Production

Reference is made to pages 78 and 79 of the Financial Section of this report. Average sales prices have been calculated by using sales quantities from the Corporation's own production as the divisor. Average production costs have been computed by using net production quantities for the divisor. The volumes of crude oil and natural gas liquids (NGL) production used for this computation are shown in the reserves table on page 83 of the Financial Section of this report. The volumes of natural gas used in the calculation are the production volumes of natural gas available for sale and thus are different from those shown in the reserves table on page 84 of the Financial Section of this report due to volumes consumed or flared. The volumes of natural gas were converted to oil-equivalent barrels based on a conversion factor of six thousand cubic feet per barrel.

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4. Gross and Net Productive Wells

	Year-End 2004				Year-End 2003			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States	30,702	11,949	9,335	5,577	33,716	13,188	9,566	5,746
Canada	7,156	5,890	5,663	2,752	7,037	5,770	5,317	2,666
Europe	1,872	594	1,304	520	1,873	604	1,387	524
Asia Pacific	1,154	433	193	164	1,509	553	853	306
Africa	562	235	18	7	355	152	16	7
Middle East	924	144	42	8	1,010	150	35	6
Other	240	78	67	25	229	74	66	24
Total	42,610	19,323	16,622	9,053	45,729	20,491	17,240	9,279

The numbers of wells operated at year-end 2004 were 18,427 gross wells and 15,216 net wells. At year-end 2003, the numbers of operated wells were 20,174 gross wells and 16,610 net wells.

5. Gross and Net Developed Acreage

	Year-End 2004		Year-End 2003	
	Gross	Net	Gross	Net
	(thousands of acres)			
United States	9,017	5,480	9,367	5,655
Canada	5,535	2,499	4,786	2,431
Europe	11,345	4,715	11,296	4,746
Asia Pacific	2,700	1,080	5,443	1,723
Africa	1,179	475	1,130	462
South America	1,331	388	1,331	388
Middle East	7,416	1,356	7,405	1,356
Caspian	487	103	487	103
Total	39,010	16,096	41,245	16,864

Note: Separate acreage data for oil and gas are not maintained because, in many instances, both are produced from the same acreage.

6. Gross and Net Undeveloped Acreage

	Year-End 2004		Year-End 2003	
	Gross	Net	Gross	Net
	(thousands of acres)			
United States	10,913	7,055	11,343	7,353
Canada	10,440	5,997	9,078	5,055
Europe	8,418	2,245	8,555	2,611
Asia Pacific	7,935	4,219	17,457	8,769
Africa	41,380	21,797	28,423	11,447
South America	27,020	19,688	15,650	15,141
Middle East	154	46	36	10
Caspian	2,322	476	2,561	516
Total	108,582	61,523	93,103	50,902

ExxonMobil's investment in developed and undeveloped acreage is comprised of numerous concessions, blocks and leases. The terms and conditions under which the Corporation maintains exploration and/or production rights to the acreage are property-specific, contractually-defined and vary significantly. Work programs are designed to ensure that the exploration potential of any property is fully evaluated before expiration. In some instances, the Corporation may elect to relinquish acreage in advance of the contractual expiration date if the evaluation process is complete and there is not a business basis for extension. In cases where additional time may be required to fully evaluate acreage, the Corporation has generally been successful in obtaining extensions.

7. Summary of Acreage Terms in Key Areas

UNITED STATES

Oil and gas leases have an exploration period ranging from one to ten years, and a production period that normally remains in effect until production ceases. In some instances, a "fee interest" is acquired where both the surface and the underlying mineral interests are owned outright.

CANADA

Exploration permits are granted for varying periods of time with renewals possible. Production leases are held as long as there is production on the lease. The majority of Cold Lake leases were taken for an initial 21-year term in 1968-1969 and renewed for a second 21-year term in 1989-1990. The exploration acreage in eastern Canada is currently held by work commitments of various amounts.

EUROPE

France

Exploration permits are granted for periods of three to five years, and are renewable up to two times accompanied by substantial acreage relinquishments: 50 percent of the acreage at first renewal; 25 percent of the remaining acreage at second renewal. A 1994 law requires a bidding process prior to granting of an exploration permit. Upon discovery of commercial hydrocarbons, a production concession is granted for up to 50 years, renewable in periods of 25 years each.

Germany

Exploration concessions are granted for an initial maximum period of five years with possible extensions of up to three years for an indefinite period. Extensions are subject to specific, minimum work commitments. Production licenses are normally granted for 20 to 25 years with multiple possible extensions as long as there is production on the license.

Netherlands

Under the new Mining Law, effective January 1, 2003, exploration and production licenses for both onshore and offshore areas are issued for a period of time necessary to perform the activities for which the license is issued. License conditions are stipulated in the Mining Law.

Exploration and production rights granted prior to January 1, 2003 remain subject to their existing terms, and differ slightly for onshore and offshore areas.

Onshore: Exploration licenses were issued for a period of time necessary to perform the activities for which the license was issued. Production concessions are granted after discoveries have been made, under conditions that are negotiated with the government. Normally, they are field-life concessions covering an area defined by hydrocarbon occurrences.

Offshore: Exploration licenses issued between 1976 and 1996 were for a ten-year period, with relinquishment of about 50 percent of the original area required at the end of six years. Exploration licenses granted after that time were for a period of time necessary to perform the activities for which the permit was issued. Production licenses are normally issued for a 40-year period.

Norway

Licenses issued prior to 1972 were for an initial period of six years and an extension period of 40 years, with relinquishment of at least one-fourth of the original area required at the end of the sixth year and another one-fourth at the end of the ninth year. Licenses issued between 1972 and 1997 were for an initial period of up to six years (with extension of the initial period of one year at a time up to ten years after 1985), and an extension period of up to 30 years, with relinquishment of at least one-half of the original area required at the end of the initial period. Licenses issued after July 1, 1997 have an initial period of up to ten years and a normal extension period of up to 30 years or in special cases of up to 50 years, and with relinquishment of at least one-half of the original area required at the end of the initial period.

United Kingdom

Acreage terms are fixed by the government and are periodically changed. For example, the regulations governing licenses issued between 1996 and 1998 provided for an initial term of three years with possible extensions of six, 15 and 24 years for a license period of 45 more years. After the second extension, the license must be surrendered in part. Licenses issued in 2002 as part of the 20th licensing round have an initial term of four years with a second term extension of four years. There is a mandatory relinquishment of all acreage that is not covered by a development plan at the end of the second term.

ASIA PACIFIC

Australia

Exploration and production activities are conducted offshore and are governed by Federal legislation. Exploration permits granted before January 1, 2003 were issued for six years with three possible five-year renewal periods. Exploration permits granted after that date are issued for six years with two possible five-year renewal periods. A 50 percent relinquishment of remaining area is mandatory at the end of each renewal period. Retention leases may be granted for resources that are not commercially viable at the time of application, but are expected to become commercially viable within 15 years. These are granted for periods of five years and renewals may be requested. Prior to September 1998, production licenses were granted initially for 21 years, with a further renewal of 21 years and thereafter renewals at the discretion of the Joint Authority, comprising Federal and State Ministers. Effective from September 1998, new production licenses are granted “indefinitely”, i.e., for the life of the field (if no operations for the recovery of petroleum have been carried on for five years, the license may be terminated).

Indonesia

Exploration and production activities in Indonesia are generally governed by cooperation contracts, usually in the form of a production sharing contract, negotiated with BPMIGAS, a government agency established in 2002 to manage upstream oil and gas activities. Formerly this activity was carried out by Pertamina, the government owned oil company, which is now a competing limited liability company.

Japan

The Mining Law provides for the granting of concessions that convey exploration and production rights. Exploration rights are granted for an initial two-year period, and may be extended for two two-year periods for gas and three two-year periods for oil. Production rights have no fixed term and continue until abandonment so long as the rights holder is fulfilling its obligations.

Malaysia

Exploration and production activities are governed by production sharing contracts negotiated with the national oil company. The more recent contracts have an overall term of 24 to 38 years with possible extensions to the exploration and/or development periods. The exploration period is five to seven years with the possibility of extensions, after which time areas with no commercial discoveries will be deemed relinquished. The development period is from four to six years from commercial discovery, with the possibility of extensions under special circumstances. Areas from which commercial production has not started by the end of the development period will be deemed relinquished if no extension is granted. All extensions are subject to the national oil company's prior written approval. The total production period is 15 to 25 years from first commercial lifting, not to exceed the overall term of the contract.

Papua New Guinea

Exploration and production activities are governed by the Oil and Gas Act. Petroleum Prospecting licenses are granted for an initial term of six years with a five-year extension possible. Generally, a 50 percent relinquishment of the license area is required at the end of the initial six-year term, if extended. Petroleum Development licenses are granted for an initial 25-year period. An extension of up to 20 years may be granted at the Minister's discretion. Petroleum Retention licenses may be granted for gas resources that are not commercially viable at the time of application, but may become commercially viable. Petroleum Retention licenses are granted for five-year terms, and may be extended twice for a maximum retention time of 15 years.

Russia

Acreage terms are fixed by the production sharing agreement (PSA) that became effective in 1996 between the Russian government and the Sakhalin I consortium, of which ExxonMobil is the operator. The term of the PSA is 20 years from the Declaration of Commerciality, which would be 2021. The term may be extended thereafter in 10-year increments as specified in the PSA.

Thailand

The Petroleum Act of 1971 allows production under ExxonMobil's concession for 30 years with a possible ten-year extension at terms generally prevalent at the time.

AFRICA

Angola

Exploration and production activities are governed by production sharing agreements with an initial exploration term of four years and an optional second phase of two to three years. The production period is for 25 years and agreements generally provide for a negotiated extension.

Cameroon

Exploration and production activities are governed by various agreements negotiated with the national oil company and the government of Cameroon. Exploration permits are granted for terms from four to 16 years and are generally renewable for multiple periods up to four years each. Upon commercial discovery, mining concessions are issued for a period of 25 years with one 25-year extension.

Chad

Exploration permits are issued for a period of five years, and are renewable for one or two further five-year periods. The terms and conditions of the permits, including relinquishment obligations, are specified in a negotiated Convention. The production term is for 30 years and may be extended at the discretion of the government.

Equatorial Guinea

Exploration and production activities are governed by production sharing contracts negotiated with the State Ministry of Mines and Energy. The exploration periods are for ten to 15 years with limited relinquishments in the absence of commercial discoveries. The production period for crude oil is 30 years while the production period for gas is 50 years.

Nigeria

Exploration and production activities in the deepwater offshore areas are typically governed by production sharing contracts (PSCs) with the national oil company, the Nigerian National Petroleum Corporation (NNPC). NNPC holds the underlying Oil Prospecting License (OPL) and any resulting Oil Mining Lease (OML). The terms of the PSCs are generally 30 years, including a ten-year exploration period (an initial exploration phase plus one or two optional periods) covered by an OPL. Upon commercial discovery, an OPL may be converted to an OML. Partial relinquishment is required under the PSC at the end of the ten-year exploration period, and OMLs have a 20-year production period that may be extended.

Some exploration activities are carried out in deepwater by joint ventures with local companies holding interests in an OPL. OPLs in deepwater offshore areas are valid for ten years and are non-renewable, while in all other areas the licenses are for five years and also are non-renewable. Demonstrating a commercial discovery is the basis for conversion of an OPL to an OML.

OMLs granted prior to the 1969 Petroleum Act (i.e., under the Mineral Oils Act 1914, repealed by the 1969 Petroleum Act) were for 30 years onshore and 40 years in offshore areas and are renewable upon 12 months' written notice, for further periods of 30 and 40 years, respectively. Operations under these pre-1969 OMLs are conducted under a joint venture agreement with NNPC rather than a PSC.

OMLs granted under the 1969 Petroleum Act, which include all deepwater OMLs, have a maximum term of 20 years without distinction for onshore or offshore location and are renewable, upon 12 months' written notice, for another period of 20 years. OMLs not held by NNPC are also subject to a mandatory 50 percent relinquishment after the first ten years of their duration.

The Memorandum of Understanding (MOU) defining commercial terms applicable to existing joint venture oil production was renegotiated and executed in 2000. The MOU is effective for a minimum of three years with possible extensions on mutual agreement and is terminable on one calendar year's notice.

SOUTH AMERICA

Argentina

The onshore concession terms in Argentina are up to four years for the initial exploration period, up to three years for the second exploration period and up to two years for the third exploration period. A 50 percent relinquishment is required after each exploration period. An extension after the third exploration period is possible for up to five years. The total production term is 25 years with a ten-year extension possible, once a field has been developed.

Venezuela

Exploration and production activities are governed by contracts negotiated with the national oil company. Exploration activity is covered by risk/profit sharing contracts where exploration blocks are awarded for 35 years. Production licenses are awarded for 20 years under production service agreements.

Strategic association agreements (such as the Cerro Negro project) are typically limited to those projects that require vertical integration for extra heavy crude oil. Contracts are awarded for 35 years. Significant amendments to the contract terms require Venezuelan congressional approval.

MIDDLE EAST

Qatar

The State of Qatar grants gas production development project rights to develop and supply gas from the offshore North Field to permit the economic development and production of gas reserves sufficient to satisfy the gas and LNG sales obligations of these projects.

Republic of Yemen

Production sharing agreements (PSAs) negotiated with the government entitle the company to participate in exploration operations within a designated area during the exploration period. In the event of a commercial oil discovery, the company is entitled to proceed with development and production operations during the development period. The length of these periods and other specific terms are negotiated prior to executing the PSA. Existing production operations have a development period extending 20 years from first commercial declaration made in November 1985 for the Marib PSA and June 1995 for the Jannah PSA.

United Arab Emirates

Exploration and production activities in the Emirate of Abu Dhabi are governed by a 75-year oil concession agreement executed in 1939 and subsequently amended through various agreements with the government of Abu Dhabi.

CASPIAN

Azerbaijan

The production sharing agreement (PSA) for the development of the Azeri-Chirag-Gunashli field (commonly known as the Megastructure) is established for an initial period of 30 years starting from the PSA execution date in 1994.

Other exploration and production activities are governed by PSAs negotiated with the national oil company of Azerbaijan. The exploration period consists of three or four years with the possibility of a one to three-year extension. The production period, which includes development, is for 25 years or 35 years with the possibility of one or two five-year extensions.

Kazakhstan

Onshore: Exploration and production activities are governed by the production license, exploration license and joint venture agreements negotiated with the Republic of Kazakhstan. Existing production operations have a 40-year production period that commenced in 1993.

Offshore: Exploration and production activities are governed by a production sharing agreement negotiated with the Republic of Kazakhstan. The exploration period is six years with possible extensions. The production period, which includes development, is for 20 years with the possibility of two ten-year extensions.

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8. Number of Net Productive and Dry Wells Drilled

	2004	2003	2002
A. Net Productive Exploratory Wells Drilled			
United States	11	13	12
Canada	2	13	20
Europe	3	4	2
Asia Pacific	2	2	2
Africa	2	4	10
Middle East	—	—	—
Other	1	2	—
Total	21	38	46
B. Net Dry Exploratory Wells Drilled			
United States	6	10	5
Canada	4	9	4
Europe	1	3	4
Asia Pacific	—	3	1
Africa	4	3	5
Middle East	—	—	—
Other	—	—	4
Total	15	28	23
C. Net Productive Development Wells Drilled			
United States	568	598	709
Canada	466	297	430
Europe	24	36	36
Asia Pacific	23	50	67
Africa	64	59	27
Middle East	12	17	15
Other	7	3	3
Total	1,164	1,060	1,287
D. Net Dry Development Wells Drilled			
United States	13	14	18
Canada	2	16	8
Europe	2	2	2
Asia Pacific	—	—	1
Africa	—	1	—
Middle East	1	1	—
Other	—	—	—
Total	18	34	29
Total number of net wells drilled	1,218	1,160	1,385

9. Present Activities

A. Wells Drilling

	Year-End 2004		Year-End 2003	
	Gross	Net	Gross	Net
United States	179	81	132	62
Canada	31	17	152	92
Europe	32	8	38	12
Asia Pacific	20	11	10	5
Africa	80	33	78	27
Middle East	38	16	18	3
Other	28	4	24	3
Total	408	170	452	204

B. Review of Principal Ongoing Activities in Key Areas

During 2004, ExxonMobil's activities were conducted, either directly or through affiliated companies, by ExxonMobil Exploration Company (for exploration), by ExxonMobil Development Company (for large development activities), by ExxonMobil Production Company (for producing and smaller development activities) and by ExxonMobil Gas & Power Marketing Company (for gas marketing). During this same period, some of ExxonMobil's exploration, development, production and gas marketing activities were also conducted in Canada by the Resources Division of Imperial Oil Limited, which is 69.6 percent owned by ExxonMobil.

Some of the more significant ongoing activities are set forth below:

UNITED STATES

Exploration and delineation of additional hydrocarbon resources continued in 2004. At year-end 2004, ExxonMobil's acreage totaled 12.5 million net acres, of which 3.3 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska. A total of 16.6 net exploration and delineation wells were completed during 2004.

During 2004, 542.5 net development wells were completed within and around mature fields in the inland lower 48 states and 8.0 net development wells were completed offshore in the Pacific. Construction continued on an acid gas injection project to increase existing plant capacity at the Shute Creek treating facility in La Barge, Wyoming, and tight gas development has been initiated in the Piceance Basin in Colorado. Participation in Alaska production and development continued and a total of 21.8 net development wells were drilled. On Alaska's North Slope, activity continued on the Western Region Development Project (primarily the Orion field) with development drilling and conceptual engineering for facility expansions.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2004 was 3.1 million acres. A total of 8.1 net development wells were completed during the year and development continued on several Gulf of Mexico projects. Production began from the South Diana subsea deepwater field in March 2004. Production began from the first phase of the Llano subsea development in May 2004. Hull construction was completed and topsides construction continued on the semi-submersible production and drilling vessel for the Thunder Horse development.

CANADA

ExxonMobil's year-end 2004 acreage holdings totaled 8.5 million net acres, of which 4.1 million net acres were offshore. A total of 474.4 net exploration and development wells were completed during the year.

Gross production from Cold Lake averaged 126 thousand barrels per day during 2004. In eastern Canada, the South Venture field of the Sable Offshore Energy Project came online.

EUROPE

France

ExxonMobil's acreage at year-end 2004 was 0.1 million net onshore acres, with 1.0 net exploration and development well completed during the year.

Germany

A total of 2.3 million net onshore acres and 0.2 million net offshore acres were held by ExxonMobil at year-end 2004, with 4.3 net exploration and development wells completed during the year.

Netherlands

ExxonMobil's interest in licenses totaled 1.9 million net acres at year-end 2004, 1.5 million acres onshore and 0.4 million acres offshore. During 2004, 1.6 net exploration and development wells were drilled. Offshore, the K/7-FB field began production in late December 2003, and the K/15-FB-South field began production in July 2004. Onshore, a multi-year project is underway to renovate production clusters and install new compression to maintain capacity and extend field life.

Norway

ExxonMobil's net interest in licenses at year-end 2004 totaled approximately 1.1 million acres, all offshore. ExxonMobil participated in 12.6 net exploration and development well completions in 2004. Production was initiated at the Ringhorne Jurassic field in March 2004, at the Vigdis East field in May 2004, and at the Sleipner West Alpha North field and the Sleipner West compression project in October 2004. New development projects at Kristin and Ormen Lange are in progress.

United Kingdom

ExxonMobil's net interest in licenses at year-end 2004 totaled approximately 1.3 million acres, all offshore. A total of 10.8 net exploration and development wells were completed during the year. The Goldeneye project started first production in late 2004. The Arthur field project was progressed in 2004 and production was initiated early in 2005. Project development progressed on the Cutter field.

ASIA PACIFIC

Australia

ExxonMobil's net year-end 2004 acreage holdings totaled 1.4 million acres, all offshore. ExxonMobil drilled a total of 3.9 net exploration and development wells in 2004.

Indonesia

ExxonMobil had acreage of 2.7 million net acres at year-end 2004, 1.7 million acres offshore and 1.0 million acres onshore.

Japan

ExxonMobil's net offshore acreage was 36 thousand acres at year-end 2004.

Malaysia

ExxonMobil had interests in production sharing contracts covering 0.5 million net acres offshore Malaysia at year-end 2004. During the year, a total of 20.2 net exploration and development wells were completed. Development and infill drilling wells were successfully completed at eight platforms: Guntong-C, Semangkok-A, Semangkok-B, Larut-A, Tapis-F, Angsi-A, Angsi-C and Angsi-E. First oil was produced from Tapis-F in 2004. Drilling activities are currently ongoing at Semangkok-B, Irong Barat-C and Angsi-A.

Papua New Guinea

A total of 0.6 million net onshore acres were held by ExxonMobil at year-end 2004, with 0.8 net development wells completed during the year.

Russia

ExxonMobil's net acreage holdings at year-end 2004 were 85 thousand acres, all offshore. Construction and drilling activities have commenced on Phase 1 of Sakhalin I. Phase 1 facilities will include an offshore platform, onshore drill site for extended reach drilling to offshore oil zones, an onshore processing plant, an oil pipeline from Sakhalin Island to the Russian mainland and a mainland terminal for shipment of oil by tanker.

Thailand

ExxonMobil's net onshore acreage totaled 21 thousand acres at year-end 2004. The total net well completions in 2004 were 0.2 development wells.

AFRICA

Angola

ExxonMobil's year-end 2004 acreage holdings totaled 1.3 million net offshore acres and 7.7 net exploration and development wells were completed during the year. Production began at the ExxonMobil-operated Kizomba A development on Block 15 and construction is underway on the Kizomba B development. On the non-operated Block 17, construction is underway on the Dalia development, and engineering and design work is proceeding on the Rosa discovery.

Cameroon

ExxonMobil's acreage totaled 0.3 million net offshore acres at year-end 2004, with 0.4 net development wells completed during the year.

Chad

ExxonMobil's net year-end 2004 acreage holdings consisted of 3.3 million onshore acres, with 44.0 net exploration and development wells completed during the year. The Chad-Cameroon oil development and pipeline project reached full production in 2004, with start-up of the Kome and Bolobo fields.

Equatorial Guinea

ExxonMobil's acreage totaled 0.5 million net offshore acres at year-end 2004, with 6.1 net development wells completed during the year.

Nigeria

ExxonMobil's net acreage totaled 1.7 million offshore acres at year-end 2004, with 11.0 net exploration and development wells completed during the year. Drilling continued in 2004 on the new Yoho and Awawa platforms, installed in 2003, as development continued at the ExxonMobil-operated Yoho field (OML 104). The Yoho Floating, Storage and Offloading (FSO) facility also arrived on site and installation is progressing. Construction also continued on the Amenam-Kpono Phase 2 Gas project. Construction, installation and drilling activities continued at the Bonga field (OML 118), and drilling and construction activities are underway on the ExxonMobil-operated Erha field (OPL 209). Construction and installation are underway on the ExxonMobil-operated East Area Additional Oil Recovery project. The financing agreement and construction contracts for the ExxonMobil-operated East Area NGL project were signed in 2004.

OTHER COUNTRIES

Argentina

ExxonMobil's net acreage totaled 0.3 million onshore acres at year-end 2004 and there were 0.5 net development wells completed during the year.

Venezuela

ExxonMobil's net year-end 2004 acreage holdings totaled 0.2 million onshore acres, with 3.3 net development wells completed during the year.

Azerbaijan

At year-end 2004, ExxonMobil's net acreage, located in the Caspian Sea offshore of Azerbaijan, totaled 0.1 million acres. During the year, 0.5 net exploration and development wells were completed. At the Azeri-Chirag-Gunashli (ACG) Early Oil project, oil production with pressure support from water injection is ongoing. Engineering and construction is underway on the first, second and third phases of full field development at ACG.

Kazakhstan

ExxonMobil's net acreage totaled 0.2 million acres onshore and 0.2 million acres offshore at year-end 2004, with 4.0 net exploration and development wells completed during 2004. At Tengiz, construction of the 300 thousand barrels of oil per day (gross) expansion project began in 2003. Approval of the Kashagan field's development plan by the Republic of Kazakhstan was received in February 2004. Detailed engineering of the initial phase of development is underway and the majority of the fabrication contracts have been placed.

Qatar

Production and development activities continued on natural gas projects in Qatar. Liquefied natural gas (LNG) operating companies include:

Qatar Liquefied Gas Company Limited — (QG)
Qatar Liquefied Gas Company Limited (II) — (QGII)
Ras Laffan Liquefied Gas Company Limited — (RL)
Ras Laffan Liquefied Gas Company Limited (II) — (RLII)

In addition, an ExxonMobil subsidiary is currently constructing natural gas production facilities for the Al Khaleej Gas (AKG) project to supply pipeline gas to domestic industrial customers.

At the end of 2004, 42 (gross) wells supplied natural gas to currently producing LNG facilities and drilling is underway to complete wells that will supply the new QGII, RLII and AKG projects.

Qatar LNG capacity volumes at year-end included 9.4 MTA (millions of metric tons per year) in QG trains 1-3 and a combined 11.3 MTA in RL trains 1-2 and RL II train 3. An expansion project is underway to increase the capacity of QG trains 1-3 to 9.7 MTA. Construction of QG II trains 4-5 will add planned capacity of 15.6 MTA when complete. In addition, construction of RL II trains 4-5 will add planned capacity of 9.4 MTA when complete.

The conversion factor to translate Qatar LNG volumes (millions of metric tons - MT) into gas volumes (billions of cubic feet - BCF) is dependent on the gas quality and the quality of the LNG produced. The conversion factors are approximately 46 BCF/MT for QG trains 1-3, RL trains 1-2 and RLII train 3 and approximately 49 BCF/MT for QGII trains 4-5 and RLII trains 4-5.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 0.9 million acres onshore at year-end 2004. During the year, 4.8 net development wells were completed.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi onshore oil concession was 0.5 million acres at year-end 2004. During the year, 7.8 net exploratory and development wells were completed.

WORLDWIDE EXPLORATION

At year-end 2004, exploration activities were underway in several areas in which ExxonMobil has no established production operations and thus are not included above. A total of 35 million net acres were held at year-end 2004, and 1.2 net exploration wells were completed during the year in these countries.

Information with regard to mining activities follows:

Syncrude Operations

Syncrude is a joint-venture established to recover shallow deposits of tar sands using open-pit mining methods, to extract the crude bitumen, and to produce a high-quality, light (32 degree API), sweet, synthetic crude oil. The Syncrude operation, located near Fort McMurray, Alberta, Canada, exploits a portion of the Athabasca Oil Sands Deposit. The location is readily accessible by public road. The produced synthetic crude oil is shipped from the Syncrude site to Edmonton, Alberta by Alberta Oil Sands Pipeline Ltd. Since start-up in 1978, Syncrude has produced about 1.5 billion barrels of synthetic crude oil. Imperial Oil Limited is the owner of a 25 percent interest in the joint-venture. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited.

Operating License and Leases

Syncrude has an operating license issued by the Province of Alberta which is effective until 2035. This license permits Syncrude to mine tar sands and produce synthetic crude oil from approved development areas on tar sands leases. Syncrude holds eight tar sands leases covering approximately 252,000 acres in the Athabasca Oil Sands Deposit which were issued by the Province of Alberta. The leases are automatically renewable as long as tar sands operations are ongoing or the leases are part of an approved development plan. Syncrude leases 10, 12, 17, 22 and 34 (containing proven reserves) and leases 29, 30 and 31 (containing no proven reserves) are included within a development plan approved by the Province of Alberta. There were no known previous commercial operations on these leases prior to the start-up of operations in 1978.

Operations, Plant and Equipment

Operations at Syncrude involve three main processes: open pit mining, extraction of crude bitumen and upgrading of crude bitumen into synthetic crude oil. In the Base mine (lease 17), the mining and transportation system uses draglines, bucketwheel reclaimers and belt conveyors. In the

North mine (leases 17 and 22) and in the Aurora mine (leases 10, 12 and 34), truck, shovel and hydrotransport systems are used. Production from the Aurora mine commenced in 2000. The extraction facilities, which separates crude bitumen from sand, are capable of processing approximately 545,000 tons of tar sands a day, producing 110 million barrels of crude bitumen a year. This represents recovery capability of about 92 percent of the crude bitumen contained in the mined tar sands.

Crude bitumen extracted from tar sands is refined to a marketable hydrocarbon product through a combination of carbon removal in two large, high-temperature, fluid-coking vessels and by hydrogen addition in high-temperature, high-pressure, hydrocracking vessels. These processes remove carbon and sulfur and reformulate the crude into a low viscosity, low sulfur, high-quality synthetic crude oil product. In 2004, this upgrading process yielded 0.855 barrels of synthetic crude oil per barrel of crude bitumen. In 2004 about 46 percent of the synthetic crude oil was processed by Edmonton area refineries and the remaining 54 percent was pipelined to refineries in eastern Canada and exported, primarily to the United States. Electricity is provided to Syncrude by a 270 megawatt electricity generating plant and an 80 megawatt electricity generating plant, both located at Syncrude. The generating plants are owned by the Syncrude participants. Imperial Oil Limited’s 25 percent share of net investment in plant, property and equipment, including surface mining facilities, transportation equipment and upgrading facilities was about $2.3 billion at year end 2004.

Synthetic Crude Oil Reserves

The crude bitumen is contained within the unconsolidated sands of the McMurray Formation. Ore bodies are buried beneath 50 to 150 feet of overburden, have bitumen grades ranging from 4 to 14 weight percent and ore thickness of 115 to 160 feet. Estimates of synthetic crude oil reserves are based on detailed geological and engineering assessments of in-place crude bitumen volume, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The in-place volume, depth and grade are established through extensive and closely spaced core drilling. Proven reserves include the operating Base and North mines and the Aurora mine. In accordance with the approved mining plan, there are an estimated 2,055 million tons of extractable tar sands in the Base and North mines, with an average bitumen grade of 10.6 weight percent. In addition, at the Aurora mine, there are an estimated 4,470 million tons of extractable tar sands at an average bitumen grade of 11.1 weight percent. After deducting royalties payable to the Province of Alberta, Imperial Oil Limited estimates that its 25 percent net share of proven reserves at year end 2004 was equivalent to 757 million barrels of synthetic crude oil.

In 2001, the Syncrude owners endorsed a further development of the Syncrude resource in the area and expansion of the upgrading facilities. The Syncrude Aurora 2 and Upgrader Expansion 1 project adds a remote mining train and expands the central processing and upgrading plant. This expansion is under way and will lead to total production of about 350 thousand barrels of synthetic crude oil per day (gross) when completed.

ExxonMobil Share of Net Proven Syncrude Reserves(1)

	Synthetic Crude Oil		
	Base Mine and North Mine	Aurora Mine	Total
	(millions of barrels)		
January 1, 2004	331	450	781
Revision of previous estimate	(103)	100	(3)
Production	(11)	(10)	(21)
December 31, 2004	217	540	757

(1) Net reserves are the company's share of reserves after deducting royalties payable to the Province of Alberta.

Syncrude Operating Statistics (total operation)

	2004	2003	2002	2001	2000
Operating Statistics					
Total mined volume (millions of cubic yards)(1)	100.3	109.2	102.0	118.3	85.1
Mined volume to tar sands ratio(1)	0.94	1.15	1.05	1.15	0.96
Tar sands mined (millions of tons)	188.0	168.0	172.1	181.2	156.4
Average bitumen grade (weight percent)	11.1	11.0	11.2	11.0	11.0
Crude bitumen in mined tar sands (millions of tons)	20.9	18.5	19.2	19.9	17.2
Average extraction recovery (percent)	87.3	88.6	89.9	87.0	89.7
Crude bitumen production (millions of barrels)(2)	103.3	92.3	97.8	97.6	86.8
Average upgrading yield (percent)	85.5	86.0	86.3	84.5	84.3
Gross synthetic crude oil produced (millions of barrels)	88.4	78.4	84.8	82.4	73.2
ExxonMobil net share (millions of barrels)(3)	22	19	21	19	15

(1) Includes pre-stripping of mine areas and reclamation volumes.
(2) Crude bitumen production is equal to crude bitumen in mined tar sands multiplied by the average extraction recovery and the appropriate conversion factor.
(3) Reflects ExxonMobil's 25 percent interest in production less applicable royalties payable to the Province of Alberta.

Item 3. ***Legal Proceedings.***

On November 30, 2004, the New York State Department of Environmental Conservation ("NYSDEC") proposed a statewide settlement of petroleum bulk storage compliance issues at all active petroleum bulk storage sites in New York, and any investigation and remediation required at those sites. The proposal includes requirements that the company perform a compliance audit at each site, undertake a $1.5 million environmental benefit project, pay a penalty of $5 million, and pay oversight costs. ExxonMobil is evaluating the offer and will respond to the NYSDEC. No formal action has been taken by the NYSDEC regarding these matters.

Refer to the relevant portions of note 16 beginning on page 70 of the Financial Section of this report for additional information on legal proceedings.

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

None.

Executive Officers of the Registrant [pursuant to Instruction 3 to Regulation S-K, Item 401(b)].

Name	Age as of March 16, 2005	Title (Held Office Since)
L. R. Raymond	66	Chairman of the Board (1993)
R. W. Tillerson	52	President (2004)
E. G. Galante	54	Senior Vice President (2001)
S. R. McGill	62	Senior Vice President (2004)
J. S. Simon	61	Senior Vice President (2004)
M. W. Albers	48	President, ExxonMobil Development Company (2004)
A. T. Cejka	53	Vice President (2004)
H. R. Cramer	54	Vice President (1999)
P. J. Dingle	56	Vice President (2003)
M. J. Dolan	51	Vice President (2004)
M. E. Foster	61	Vice President (2004)
H. H. Hubble	52	Vice President—Investor Relations and Secretary (2004)
D. D. Humphreys	57	Vice President and Treasurer (2004)
G. L. Kohlenberger	52	Vice President (2002)
C. W. Matthews	60	Vice President and General Counsel (1995)
P. T. Mulva	53	Vice President and Controller (2004)
S. D. Pryor	55	Vice President (2004)
P. E. Sullivan	61	Vice President and General Tax Counsel (1995)

For at least the past five years, Messrs. Cramer, Humphreys, Matthews, McGill, Raymond, Simon and Sullivan have been employed as executives of the registrant. Mr. Tillerson was a Senior Vice President before becoming President. Mr. McGill was President of ExxonMobil Production Company before becoming Senior Vice President. Mr. Simon was President of ExxonMobil Refining & Supply Company before becoming Senior Vice President. Mr. Humphreys was Vice President and Controller before becoming Vice President and Treasurer. Mr. Mulva was Vice President—Investor Relations and Secretary before becoming Vice President and Controller.

The following executive officers of the registrant have also served as executives of the subsidiaries, affiliates or divisions of the registrant shown opposite their names during the five years preceding December 31, 2004.

Esso Exploration and Production Chad Inc.	Albers
Esso Malaysia Berhad	Dingle
Esso Production Malaysia Inc.	Dingle
Exxon Neftegas Limited	Tillerson
Exxon Ventures (CIS) Inc.	Tillerson
ExxonMobil Chemical Company	Dolan, Galante and Pryor
ExxonMobil Development Company	Albers, Foster and Tillerson
ExxonMobil Exploration Company	Cejka
ExxonMobil Fuels Marketing Company	Cramer
ExxonMobil Gas & Power Marketing Company	Dingle
ExxonMobil Global Services Company	Kohlenberger
ExxonMobil Lubricants & Petroleum Specialties Company	Kohlenberger and Pryor
ExxonMobil Production Company	Albers and Foster
ExxonMobil Refining & Supply Company	Dolan, Hubble and Pryor
Imperial Oil Limited	Mulva
Mobil Business Resources Corporation	Kohlenberger

Officers are generally elected by the Board of Directors at its meeting on the day of each annual election of directors, with each such officer serving until a successor has been elected and qualified.

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PART II

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

Reference is made to the quarterly information which appears on page 88 of the Financial Section of this report.

Issuer Purchase of Equity Securities for Quarter Ended December 31, 2004

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October, 2004	19,224,883	$ 49.10	19,224,883	
November, 2004	18,984,573	$ 50.11	18,984,573	
December, 2004	22,617,237	$ 50.67	22,617,237	
Total	60,826,693	$ 50.00	60,826,693	(See note 1)

Note 1—On August 1, 2000, the Corporation announced its intention to resume purchases of shares of its common stock for the treasury both to offset shares issued in conjunction with company benefit plans and programs and to gradually reduce the number of shares outstanding. The announcement did not specify an amount or expiration date. The Corporation has continued to purchase shares since this announcement and to report purchased volumes in its quarterly earnings releases. Purchases may be made in both the open market and through negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice.

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Item 6. ***Selected Financial Data.***

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(millions of dollars, except per share amounts)				
Sales and other operating revenue(1)	$ 291,252	$ 237,054	$ 200,949	$ 208,715	$ 227,596
(1) Excise taxes included	$ 27,263	$ 23,855	$ 22,040	$ 21,907	$ 22,356
Net income					
Income from continuing operations	$ 25,330	$ 20,960	$ 11,011	$ 15,003	$ 15,806
Discontinued operations, net of income tax	—	—	449	102	184
Extraordinary gain, net of income tax	—	—	—	215	1,730
Cumulative effect of accounting change, net of income tax	—	550	—	—	—
Net income	$ 25,330	$ 21,510	$ 11,460	$ 15,320	$ 17,720
Net income per common share					
Income from continuing operations	$ 3.91	$ 3.16	$ 1.62	$ 2.19	$ 2.27
Discontinued operations, net of income tax	—	—	0.07	0.01	0.03
Extraordinary gain, net of income tax	—	—	—	0.03	0.25
Cumulative effect of accounting change, net of income tax	—	0.08	—	—	—
Net income	$ 3.91	$ 3.24	$ 1.69	$ 2.23	$ 2.55
Net income per common share - assuming dilution					
Income from continuing operations	$ 3.89	$ 3.15	$ 1.61	$ 2.17	$ 2.24
Discontinued operations, net of income tax	—	—	0.07	0.01	0.03
Extraordinary gain, net of income tax	—	—	—	0.03	0.25
Cumulative effect of accounting change, net of income tax	—	0.08	—	—	—
Net income	$ 3.89	$ 3.23	$ 1.68	$ 2.21	$ 2.52
Cash dividends per common share	$ 1.06	$ 0.98	$ 0.92	$ 0.91	$ 0.88
Total assets	$ 195,256	$ 174,278	$ 152,644	$ 143,174	$ 149,000
Long-term debt	$ 5,013	$ 4,756	$ 6,655	$ 7,099	$ 7,280

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

Reference is made to the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" beginning on page 30 of the Financial Section of this report.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk.***

Reference is made to the section entitled "Market Risks, Inflation and Other Uncertainties" beginning on page 39, excluding the part entitled "Inflation and Other Uncertainties," of the Financial Section of this report. All statements other than historical information incorporated in this Item 7A are forward-looking statements. The actual impact of future market changes could differ materially due to, among other things, factors discussed in this report.

Item 8. ***Financial Statements and Supplementary Data.***

Reference is made to the following in the Financial Section of this report:

- Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP dated February 28, 2005, beginning on page 48 with the section entitled "Report of Independent Registered Public Accounting Firm" and continuing to page 77;
- Quarterly Information (unaudited) appearing on page 88;
- Supplemental Information on Oil and Gas Exploration and Production Activities (unaudited) appearing on pages 78 through 87; and
- Frequently Used Terms (unaudited) on pages 28 and 29.

Financial Statement Schedules have been omitted because they are not applicable or the required information is shown in the consolidated financial statements or notes thereto.

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

None.

Item 9A. ***Controls and Procedures.***

Management's Evaluation of Disclosure Controls and Procedures

As indicated in the certifications in Exhibit 31 of this report, the Corporation's chief executive officer, principal accounting officer and principal financial officer have evaluated the Corporation's disclosure controls and procedures as of December 31, 2004. Based on that evaluation, these officers have concluded that the Corporation's disclosure controls and procedures are effective in ensuring that material information required to be in this annual report is made known to them on a timely basis.

Management's Report on Internal Control over Financial Reporting

Management, including the Corporation's chief executive officer, principal accounting officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2004.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004, was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report beginning on page 48 of the Financial Section of this report.

Changes in Internal Control over Financial Reporting

There were no changes during the Corporation's last fiscal quarter that materially affected, or are reasonably likely to materially affect the Corporation's internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

Incorporated by reference to the following from the registrant's definitive proxy statement for the 2005 annual meeting of shareholders (the "2005 Proxy Statement"):

- The section entitled "Election of Directors";
- The portion entitled "Section 16(a) Beneficial Ownership Reporting Compliance" of the section entitled "Executive Compensation Tables";
- The portion entitled "Code of Ethics and Business Conduct" of the section entitled "Corporate Governance Guidelines"; and
- The "Audit Committee" portion and the membership table of the section entitled "Board Committees".

Item 11. ***Executive Compensation.***

Incorporated by reference to the section entitled "Director Compensation" and the section entitled "Executive Compensation Tables" of the registrant's 2005 Proxy Statement.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management.***

Incorporated by reference to the section entitled "Director and Executive Officer Stock Ownership" and the portion entitled "Equity Compensation Plan Information" of the section entitled "Executive Compensation Tables" of the registrant's 2005 Proxy Statement.

Item 13. ***Certain Relationships and Related Transactions.***

Incorporated by reference to the portion entitled "Director Relationships" of the section entitled "Election of Directors" of the registrant's 2005 Proxy Statement.

Item 14. ***Principal Accounting Fees and Services.***

Incorporated by reference to the section entitled "Ratification of Independent Auditors" of the registrant's 2005 Proxy Statement.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a) (1) and (2) Financial Statements:
See Table of Contents on page 25 of the Financial Section of this report.

(a) (3) Exhibits:
See Index to Exhibits beginning on page 92 of this report.

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FINANCIAL SECTION

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BUSINESS PROFILE

Financial	Earnings After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
	2004	2003	2004	2003	2004	2003	2004	2003
	(millions of dollars)				(percent)		(millions of dollars)	
Upstream								
United States	$ 4,948	$ 3,905	$ 13,355	$ 13,508	37.0	28.9	$ 1,922	$ 2,125
Non-U.S.	11,727	10,597	37,287	34,164	31.5	31.0	9,793	9,863
Total	$ 16,675	$ 14,502	$ 50,642	$ 47,672	32.9	30.4	$ 11,715	$ 11,988
Downstream								
United States	$ 2,186	$ 1,348	$ 7,632	$ 8,090	28.6	16.7	$ 775	$ 1,244
Non-U.S.	3,520	2,168	19,541	18,875	18.0	11.5	1,630	1,537
Total	$ 5,706	$ 3,516	$ 27,173	$ 26,965	21.0	13.0	$ 2,405	$ 2,781
Chemical								
United States	$ 1,020	$ 381	$ 5,246	$ 5,194	19.4	7.3	$ 262	$ 333
Non-U.S.	2,408	1,051	9,362	8,905	25.7	11.8	428	359
Total	$ 3,428	$ 1,432	$ 14,608	$ 14,099	23.5	10.2	$ 690	$ 692
Corporate and financing	(479)	1,510	14,916	6,637	—	—	75	64
Accounting change	—	550	—	—	—	—		
Total	$ 25,330	$ 21,510	$ 107,339	$ 95,373	23.8	20.9	$ 14,885	$ 15,525

See Frequently Used Terms on pages 28 and 29 for a definition and calculation of capital employed and return on average capital employed.

Operating	2004	2003
	(thousands of barrels daily)	
Net liquids production		
United States	557	610
Non-U.S.	2,014	1,906
Total	2,571	2,516
	(millions of cubic feet daily)	
Natural gas production available for sale		
United States	1,947	2,246
Non-U.S.	7,917	7,873
Total	9,864	10,119
	(thousands of oil-equivalent barrels daily)	
Oil-equivalent production (1)	4,215	4,203

(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.

	2004	2003
	(thousands of barrels daily)	
Petroleum product sales		
United States	2,872	2,729
Non-U.S.	5,338	5,228
Total	8,210	7,957
	(thousands of barrels daily)	
Refinery throughput		
United States	1,850	1,806
Non-U.S.	3,863	3,704
Total	5,713	5,510
	(thousands of metric tons)	
Chemical prime product sales		
United States	11,521	10,740
Non-U.S.	16,267	15,827
Total	27,788	26,567

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FINANCIAL SUMMARY

	2004	2003	2002	2001	2000
	(millions of dollars, except per share amounts)				
Sales and other operating revenue [1]					
Upstream	$ 23,033	$ 21,330	$ 16,484	$ 18,567	$ 21,509
Downstream	240,413	195,511	168,032	174,185	188,563
Chemical	27,781	20,190	16,408	15,943	17,501
Other	25	23	25	20	23
Total	$ 291,252	$ 237,054	$ 200,949	$ 208,715	$ 227,596
Earnings					
Upstream	$ 16,675	$ 14,502	$ 9,598	$ 10,736	$ 12,685
Downstream	5,706	3,516	1,300	4,227	3,418
Chemical	3,428	1,432	830	707	1,161
Corporate and financing	(479)	1,510	(442)	(142)	(538)
Merger-related expenses	—	—	(275)	(525)	(920)
Income from continuing operations	$ 25,330	$ 20,960	$ 11,011	$ 15,003	$ 15,806
Discontinued operations	—	—	449	102	184
Extraordinary gain	—	—	—	215	1,730
Accounting change	—	550	—	—	—
Net income	$ 25,330	$ 21,510	$ 11,460	$ 15,320	$ 17,720
Net income per common share	$ 3.91	$ 3.24	$ 1.69	$ 2.23	$ 2.55
Net income per common share – assuming dilution	$ 3.89	$ 3.23	$ 1.68	$ 2.21	$ 2.52
Cash dividends per common share	$ 1.06	$ 0.98	$ 0.92	$ 0.91	$ 0.88
Net income to average shareholders’ equity (percent)	26.4	26.2	15.5	21.3	26.4
Working capital	$ 17,396	$ 7,574	$ 5,116	$ 5,567	$ 2,208
Ratio of current assets to current liabilities	1.40	1.20	1.15	1.18	1.06
Additions to property, plant and equipment	$ 11,986	$ 12,859	$ 11,437	$ 9,989	$ 8,446
Property, plant and equipment, less allowances	$ 108,639	$ 104,965	$ 94,940	$ 89,602	$ 89,829
Total assets	$ 195,256	$ 174,278	$ 152,644	$ 143,174	$ 149,000
Exploration expenses, including dry holes	$ 1,098	$ 1,010	$ 920	$ 1,175	$ 936
Research and development costs	$ 649	$ 618	$ 631	$ 603	$ 564
Long-term debt	$ 5,013	$ 4,756	$ 6,655	$ 7,099	$ 7,280
Total debt	$ 8,293	$ 9,545	$ 10,748	$ 10,802	$ 13,441
Fixed-charge coverage ratio (times)	36.1	30.8	13.8	17.7	15.6
Debt to capital (percent)	7.3	9.3	12.2	12.4	15.4
Net debt to capital (percent) [2]	(10.7)	(1.2)	4.4	5.3	7.9
Shareholders’ equity at year end	$ 101,756	$ 89,915	$ 74,597	$ 73,161	$ 70,757
Shareholders’ equity per common share	$ 15.90	$ 13.69	$ 11.13	$ 10.74	$ 10.21
Weighted average number of common shares outstanding (millions)	6,482	6,634	6,753	6,868	6,953
Number of regular employees at year end (thousands) [3]	85.9	88.3	92.5	97.9	99.6
CORS employees not included above (thousands) [4]	19.3	17.4	16.8	19.9	18.7

(1) *Sales and other operating revenue includes excise taxes of $27,263 million for 2004, $23,855 million for 2003, $22,040 million for 2002, $21,907 million for 2001 and $22,356 million for 2000.*

(2) *Debt net of cash, excluding restricted cash. The ratio of net debt to capital including restricted cash is (16.3) percent for 2004.*

(3) *Regular employees are defined as active executive, management, professional, technical and wage employees who work full time or part time for the Corporation and are covered by the Corporation’s benefit plans and programs.*

(4) *CORS employees are employees of company-operated retail sites.*

FREQUENTLY USED TERMS

Listed below are definitions of several of ExxonMobil's key business financial performance measures. These definitions are provided to facilitate understanding of the terms and their calculation.

CASH FLOW FROM OPERATIONS AND ASSET SALES

Cash flow from operations and asset sales is the sum of the net cash provided by operating activities and proceeds from sales of subsidiaries, investments and property, plant and equipment from the Consolidated Statement of Cash Flows. This cash flow is the total sources of cash from both operating the Corporation's assets and from the divesting of assets. The Corporation employs a long-standing disciplined regular review process to ensure that all assets are contributing to the Corporation's strategic and financial objectives. Assets are divested when they are no longer meeting these objectives or are worth considerably more to others. Because of the regular nature of this activity, we believe it is useful for investors to consider sales proceeds together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

Cash flow from operations and asset sales	2004	2003	2002
		(millions of dollars)	
Net cash provided by operating activities	$ 40,551	$ 28,498	$ 21,268
Sales of subsidiaries, investments and property, plant and equipment	2,754	2,290	2,793
Cash flow from operations and asset sales	$ 43,305	$ 30,788	$ 24,061

CAPITAL EMPLOYED

Capital employed is a measure of net investment. When viewed from the perspective of how the capital is used by the businesses, it includes ExxonMobil's net share of property, plant and equipment and other assets less liabilities, excluding both short-term and long-term debt. When viewed from the perspective of the sources of capital employed in total for the Corporation, it includes ExxonMobil's share of total debt and shareholders' equity. Both of these views include ExxonMobil's share of amounts applicable to equity companies, which the Corporation believes should be included to provide a more comprehensive measure of capital employed.

Capital employed	2004	2003	2002
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	$ 195,256	$ 174,278	$ 152,644
Less liabilities and minority share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(39,701)	(33,597)	(29,082)
Total long-term liabilities excluding long-term debt and equity of minority and preferred shareholders in affiliated companies	(41,554)	(37,839)	(35,449)
Minority share of assets and liabilities	(5,285)	(4,945)	(4,210)
Add ExxonMobil share of debt-financed equity company net assets	3,914	4,151	4,795
Total capital employed	$ 112,630	$ 102,048	$ 88,698
Total corporate sources: debt and equity perspective			
Notes and loans payable	$ 3,280	$ 4,789	$ 4,093
Long-term debt	5,013	4,756	6,655
Shareholders' equity	101,756	89,915	74,597
Less minority share of total debt	(1,333)	(1,563)	(1,442)
Add ExxonMobil share of equity company debt	3,914	4,151	4,795
Total capital employed	$ 112,630	$ 102,048	$ 88,698

RETURN ON AVERAGE CAPITAL EMPLOYED

Return on average capital employed (ROCE) is a performance measure ratio. From the perspective of the business segments, ROCE is annual business segment earnings divided by average business segment capital employed (average of beginning and end-of-year amounts). These segment earnings include ExxonMobil's share of segment earnings of equity companies, consistent with our capital employed definition, and exclude the cost of financing. The Corporation's total ROCE is net income excluding the after-tax cost of financing, divided by total corporate average capital employed. The Corporation has consistently applied its ROCE definition for many years and views it as the best measure of historical capital productivity in our capital-intensive, long-term industry, both to evaluate management's performance and to demonstrate to shareholders that capital has been used wisely over the long term. Additional measures, which tend to be more cash flow based, are used for future investment decisions.

Return on average capital employed	**2004**	**2003**	**2002**
		(millions of dollars)	
Net income	$ 25,330	$21,510	$11,460
Financing costs (after tax)			
Third-party debt	(137)	(69)	(81)
ExxonMobil share of equity companies	(185)	(172)	(227)
All other financing costs – net [1]	54	1,775	(127)
Total financing costs	(268)	1,534	(435)
Earnings excluding financing costs	$ 25,598	$19,976	$11,895
Average capital employed	$107,339	$95,373	$88,342
Return on average capital employed – corporate total	23.8%	20.9%	13.5%

(1) *"All other financing costs – net" in 2003 includes interest income (after tax) associated with the settlement of a U.S. tax dispute.*

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FUNCTIONAL EARNINGS	2004	2003	2002
	(millions of dollars, except per share amounts)		
Net income (U.S. GAAP)			
Upstream			
United States	$ 4,948	$ 3,905	$ 2,524
Non-U.S.	11,727	10,597	7,074
Downstream			
United States	2,186	1,348	693
Non-U.S.	3,520	2,168	607
Chemical			
United States	1,020	381	384
Non-U.S.	2,408	1,051	446
Corporate and financing	(479)	1,510	(442)
Merger-related expenses	—	—	(275)
Income from continuing operations	$ 25,330	$ 20,960	$ 11,011
Discontinued operations	—	—	449
Accounting change	—	550	—
Net income	$ 25,330	$ 21,510	$ 11,460
Net income per common share	$ 3.91	$ 3.24	$ 1.69
Net income per common share – assuming dilution	$ 3.89	$ 3.23	$ 1.68
Special items included in net income			
Non-U.S. Upstream			
Gain on transfer of Ruhrgas shares	$ —	$ 1,700	$ —
U.K. deferred income tax adjustment	$ —	$ —	$ (215)
U.S. Downstream			
Allapattah lawsuit provision	$ (550)	$ —	$ —
Corporate and financing			
U.S. tax settlement	$ —	$ 2,230	$ —

FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual future results, including production growth; financing sources; the resolution of contingencies; the effect of changes in prices; interest rates and other market conditions; and environmental and capital expenditures could differ materially depending on a number of factors, such as the outcome of commercial negotiations; changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; and other factors discussed herein and under the caption “Factors Affecting Future Results” in Item 1 of ExxonMobil’s 2004 Form 10-K.

OVERVIEW

The following discussion and analysis of ExxonMobil’s financial results, as well as the accompanying financial statements and related notes to consolidated financial statements to which they refer, are the responsibility of the management of Exxon Mobil Corporation. The Corporation’s accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbon-based products. The Corporation’s business model involves the production (or purchase), manufacture and sale of physical products, and all commercial activities are directly in support of the underlying physical movement of goods.

This straightforward approach extends to the financing of the business. In evaluating business or investment opportunities, the Corporation views as economically equivalent any debt obligation, whether included on the face of the consolidated balance sheet, or disclosed as other debt-like obligations in notes to the financial statements, such as ExxonMobil’s share of equity company debt and noncancelable, long-term operating leases. This consistent, conservative approach to financing the capital-intensive needs of the Corporation has helped ExxonMobil to sustain the “triple-A” status of its long-term debt securities for 86 years.

ExxonMobil, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well positioned to participate in substantial investments to develop new energy supplies. While commodity prices remain volatile on a short-term basis depending on supply and demand, ExxonMobil’s investment decisions are based on our long-term outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Annual volumes are based on individual field production profiles, which are also updated annually. Prices for natural gas and other products are based on corporate plan assumptions developed annually by major region and used for investment evaluation purposes. Potential investment opportunities are tested over a wide range of economic scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects. ExxonMobil views return on capital employed as the best measure of historical capital productivity.

BUSINESS ENVIRONMENT AND OUTLOOK

Upstream

The Corporation expects worldwide economic growth to average just under 3 percent per year through 2030. This growth, and rising personal incomes notably in developing nations, should increase global energy demand by 1.7 percent per year, reaching 50 percent more than today by 2030. Oil, natural gas and coal are expected to remain the predominant fuels through the middle of the century. The share of oil and gas in the world’s energy supply, close to 60 percent today, should remain relatively stable, and total fossil fuels, including coal, will account for about 80 percent of the energy mix. In the very long term, the energy mix will likely become more diversified. However, for the foreseeable future, fossil fuels are the only energy forms with the scale and versatility to meet the challenge of growing world energy demand.

Oil demand should grow at 1.5 percent per year, with increasing use of oil in the transportation sector. However, natural gas is expected to be the fastest-growing primary energy source, capturing about 30 percent of the growth in total energy demand, and reaching one quarter of the total energy supply. About half of the growth in gas demand will likely be to meet worldwide electricity demand that is expected to double by 2030. The Corporation expects the liquefied natural gas (LNG) market to quadruple, helping to meet rising import dependency in Europe, North America and Asia. With equity positions in many of the largest remote gas accumulations in the world, the Corporation is positioned to benefit from its technology advances in gas liquefaction, transportation and regasification that enable distant gas supplies to reach markets economically.

On average, the world’s oil and gas fields are declining in production at between 4 percent and 6 percent per year. While large resources exist, technology advances remain critical to increasing future oil and gas supplies. Emerging technologies promise to further advance our capability to extend recoverable resources worldwide. The cost to develop these resources is also very large. According to the International Energy Agency, the investment required to meet total oil and gas energy needs worldwide through 2030 will be about $200 billion per year.

ExxonMobil maintains the largest portfolio of exploration and development opportunities among the international oil companies, which enables the selectivity required to optimize total profitability and mitigate overall political and technical risks. As future development projects bring new resources on line, the Corporation expects a shift in the geographic mix of production volumes between now and 2010. For example, oil and natural gas output from West Africa, the Caspian, the Middle East and Russia will more than double during the next six years based on current capital project execution plans. Currently, these growth areas account for less than 20 percent of the Corporation’s production. By the end of the decade, they are expected to generate about 40 percent of total volumes. Production from established areas, including Europe and North America, will decline as a percentage of the Corporation’s total production but still is expected to represent over half of 2010 volumes.

In addition to a changing geographic mix, there will also be a change in the type of opportunities from which volumes are produced. Production using arctic technology, deepwater drilling and production systems, heavy oil recovery processes and LNG is expected to grow from 20 percent to 40 percent of the Corporation’s output between now and 2010. The Corporation’s overall volume capacity outlook, based on projects coming on stream as anticipated, is for production capacity

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

increases to average 3 percent annually through 2010. However, actual volume increases will vary from year to year due to timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, price effects on production sharing contracts and other factors described under the caption "Factors Affecting Future Results" in Item 1 of ExxonMobil's 2004 Form l0-K.

Restructuring of our European gas marketing operations has progressed in anticipation of the impact of the European Gas Directives. Part of this effort includes a Heads of Agreement (HOA) whereby Esso Nederland B.V. and Shell Nederland B.V. will agree to transfer their ownership share of 25 percent each in Gasunie's gas transportation business to the State of the Netherlands. As specified in the HOA, the State of the Netherlands will pay a total net compensation in the amount of 2.78 billion Euros to the Dutch company Nederlandse Aardolie Maatschappij B.V., jointly owned by ExxonMobil and Shell. The parties intend to finalize the restructuring by mid-2005, and it is anticipated that, at that time, this step will have a positive impact on the Corporation's results. The restructuring will position ExxonMobil to compete effectively in the future European gas market and enable us to directly sell more of our equity production.

Downstream

The downstream industry environment remains very competitive. Long-term real refining margins have historically declined at a rate of about 2 percent per year and the intense competition in the retail fuels market has driven long-term real margins down by 4 percent per year. The outlook is for modest industry growth in mature markets with increasing requirements for regulatory investments.

Refining margins are a function of the difference between what a refinery pays for its raw materials (primarily crude oil) and the market prices for the range of products produced (primarily gasoline, heating oil, jet fuel and fuel oil). Crude oil and many products are widely traded with published prices, including those quoted on multiple exchanges around the world (e.g., New York Mercantile Exchange and International Petroleum Exchange). Prices for these commodities (crude and various products) are determined by the global marketplace and are impacted by many industry factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, seasonality and weather. These prices and factors are continuously monitored and serve as input to decisions about which raw materials to buy, facilities to operate and products to make. However, there are no reliable indicators of future market factors that accurately predict changes in margins from period to period.

The objectives of ExxonMobil's Downstream strategies are to position the Corporation to be the industry leader and outperform competition under a variety of market conditions. These strategies include maintaining best-in-class operations in all respects, maximizing value from leading-edge technology, capitalizing on integration with other ExxonMobil businesses and providing quality, valued products and services to the Corporation's customers. ExxonMobil has an ownership interest in 45 refineries, located in 25 countries, with distillation capacity of 6.4 million barrels per day and lubricant basestock manufacturing capacity of about 145 thousand barrels per day. ExxonMobil's fuels marketing business portfolio includes operations in over 100 countries on six continents, serving a globally diverse customer base. World-class scale and integration, industry-leading efficiency, leading-edge technology and globally respected brands enable ExxonMobil to take advantage of attractive emerging-growth opportunities around the globe. For example, our assets are well-positioned and configured to supply demand growth in Asia Pacific, which we estimate will be 3 percent annually through 2020.

Chemical

The strength of the global economy supported strong demand growth for petrochemical products in 2004. Demand growth in Asia benefited from continued economic and industrial production growth, and the North American market recovered from weak conditions in 2003. Growth in Europe was moderate, consistent with the less favorable economic environment. As a result of strong demand growth and limited new capacity additions, regional and global supply demand balances tightened, supporting higher prices and margins despite increased feedstock costs. ExxonMobil's portfolio includes many of the largest-volume and highest-growth petrochemicals in the global economy. In addition to being a worldwide supplier of primary petrochemical products, the Corporation also has a diverse portfolio of less cyclical business lines. The Corporation's competitive advantages are achieved through its business mix, investment discipline, integration of chemical capacity with large refining complexes or upstream gas processing, operational excellence, including leading proprietary technology, and product application expertise.

REVIEW OF 2004 AND 2003 RESULTS

	2004	2003	2002
		(millions of dollars)	
Income from continuing operations	$ 25,330	$ 20,960	$ 11,011
Discontinued operations	—	—	449
Accounting change	—	550	—
Net income (U.S. GAAP)	$ 25,330	$ 21,510	$ 11,460

2004

Net income in 2004 of $25,330 million was the highest ever for the Corporation, up $3,820 million from 2003. Net income in 2004 included a one-time special charge of $550 million relating to the Allapattah lawsuit provision. Interest expense in 2004 increased to $638 million compared to $207 million in 2003, reflecting the interest component of the Allapattah lawsuit provision.

Total assets at December 31, 2004, of $195 billion increased by approximately $21 billion from 2003, reflecting strong earnings and the Corporation's active investment program, particularly in the Upstream.

2003

Net income in 2003 was $21,510 million, an increase of $10,050 million from 2002. Excluding a $550 million positive impact for the required adoption of Statement of Financial Accounting Standards No. 143 (FAS 143) relating to accounting for asset retirement obligations, income from continuing operations was $20,960 million. 2003 net income also included one-time special items of $2,230 million relating to the positive settlement of a long-running U.S. tax dispute and $1,700 million from a gain on the transfer of shares in Ruhrgas AG, a German gas transmission company. Interest expense in 2003 was $207 million compared to $398 million in 2002, reflecting lower debt levels and nondebt-related items.

Total assets at December 31, 2003, of $174 billion increased by approximately $22 billion from 2002, reflecting the Corporation's active investment program and the effect of the weaker U.S. dollar.

Upstream

	2004	2003	2002
	(millions of dollars)		
Upstream			
United States	$ 4,948	$ 3,905	$ 2,524
Non-U.S.	11,727	10,597	7,074
Total	$ 16,675	$ 14,502	$ 9,598

2004

Upstream earnings of $16,675 million increased $2,173 million due to higher liquids and natural gas realizations. Upstream earnings for 2003 included a $1,700 million special item from a gain on the transfer of shares in Ruhrgas AG. Absent this, Upstream earnings increased $3,873 million in 2004. Oil-equivalent production was up 3 percent versus 2003 excluding price-related entitlement effects and divestment impacts. Including these impacts, total oil-equivalent production was flat with 2003. Liquids production of 2,571 Kbd (thousands of barrels daily) increased 55 Kbd from 2003. Production increases in West Africa and Norway were partly offset by natural field decline in mature areas, entitlement effects and divestment impacts. Natural gas production of 9,864 mcfd (millions of cubic feet daily) in 2004 compared with 10,119 mcfd in 2003. The start-up of an additional LNG train in Qatar and contributions from projects and work programs were more than offset by natural field decline, divestment impacts and entitlement effects. Earnings from U.S. Upstream operations for 2004 of $4,948 million were $1,043 million higher than 2003 due to higher realizations partly offset by lower production volumes. Earnings outside the U.S. for 2004 of $11,727 million were $1,130 million higher than 2003 due to improved realizations and higher production volumes. Earnings outside the U.S. for 2003 included a $1,700 million special item from a gain on the transfer of shares in Ruhrgas AG.

2003

Upstream earnings totaled $14,502 million, including $1,700 million from a gain on the transfer of shares in Ruhrgas AG. Absent this, Upstream earnings increased by $3,204 million from 2002 due to higher liquids and natural gas realizations. Total oil-equivalent production was down 1 percent. Liquids production of 2,516 Kbd increased 20 Kbd from 2002. Production increases from new projects in West Africa, Norway and Canada, and lower OPEC-driven quota constraints, were partly offset by natural field decline, operational problems in the North Sea and West Africa and the impact of the national strike in Venezuela. Natural gas production of 10,119 mcfd in 2003 compared with 10,452 mcfd in 2002. Higher demand in the first half of the year in Europe and contributions from new projects and work programs were more than offset by natural field decline, reduced entitlements and operational outages in the North Sea. Improved earnings from both U.S. and non-U.S. Upstream operations were driven by higher liquids and natural gas realizations. Earnings from U.S. Upstream operations for 2003 were $3,905 million, an increase of $1,381 million. Earnings outside the U.S. for 2003, including $1,700 million from a gain on the transfer of shares in Ruhrgas AG, were $10,597 million. Earnings outside the U.S. for 2002, including a special charge of $215 million relating to a United Kingdom tax rate change, were $7,074 million.

Downstream

	2004	2003	2002
	(millions of dollars)		
Downstream			
United States	$2,186	$1,348	$ 693
Non-U.S.	3,520	2,168	607
Total	$5,706	$3,516	$ 1,300

2004

Downstream earnings totaled $5,706 million, including a special charge of $550 million relating to the Allapattah lawsuit provision. Absent this, Downstream earnings increased $2,740 million due to stronger worldwide refining margins and higher refinery throughput partly offset by weaker marketing margins. Earnings also benefited from a planned reduction in inventories as a result of optimizing operations around the world. Petroleum product sales of 8,210 Kbd were 253 Kbd higher than 2003, largely related to increased refinery runs due to strong margins and more efficient operations. Refinery throughput was 5,713 Kbd compared with 5,510 Kbd in 2003. U.S. Downstream earnings of $2,186 million, including the one-time special charge relating to the Allapattah lawsuit provision, increased by $838 million. Non-U.S. Downstream earnings of $3,520 million were $1,352 million higher than 2003.

2003

Downstream earnings of $3,516 million increased by $2,216 million from 2002, reflecting higher worldwide refining and marketing margins. Earnings also benefited from a planned reduction in inventories as a result of optimizing operations around the world. Petroleum product sales of 7,957 Kbd were 200 Kbd higher than 2002, largely related to increased refinery runs due to strong margins and higher demand for distillates. Refinery throughput was 5,510 Kbd compared with 5,443 Kbd in 2002. U.S. Downstream earnings of $1,348 million increased by $655 million, reflecting higher refining and marketing margins partly offset by increased refinery turnaround activity in the year. Non-U.S. Downstream earnings of $2,168 million were $1,561 million higher than 2002 due to higher refining and marketing margins, increased refinery runs and positive inventory impacts.

Chemical

	2004	2003	2002
	(millions of dollars)		
Chemical			
United States	$1,020	$ 381	$384
Non-U.S.	2,408	$ 1051	446
Total	$3,428	$1,432	$830

2004

Chemical earnings of $3,428 million were up $1,996 million from 2003. Earnings benefited from improved worldwide margins, higher volumes and favorable foreign exchange effects. Prime product sales were a record 27,788 kt (thousands of metric tons), an increase of 1,221 kt from 2003, reflecting improved worldwide demand. Prime product sales are total chemical product sales including ExxonMobil's share of equity company volumes and finished-product transfers to the Downstream business. Carbon black oil and sulfur volumes are excluded. U.S. Chemical earnings of $1,020 million were $639 million higher than 2003 with higher margins and increased volumes on improved demand. Non-U.S. Chemical earnings of $2,408 million were $1,357 million higher than 2003 due to higher margins, strong demand in Asia and favorable foreign exchange effects.

2003

Chemical earnings of $1,432 million were up $602 million from 2002. Earnings benefited from improved worldwide margins and favorable foreign exchange effects. Prime product sales of 26,567 kt were in line with sales of 26,606 kt in 2002. U.S. Chemical earnings of $381 million were $3 million lower than 2002 with higher margins offset by lower volumes on weaker demand. Non-U.S. Chemical earnings of $1,051 million were $605 million higher than 2002 due to higher margins, strong demand in Asia and favorable foreign exchange effects.

All Other Segments

	2004	2003	2002
	(millions of dollars)		
All other segments			
Corporate and financing	$(479)	$1,510	$(442)
Merger-related expenses	—	—	(275)
Discontinued operations	—	—	449
Accounting change	—	550	—
Total	$(479)	$2,060	$(268)

2004

Corporate and financing expenses in 2004 were $479 million. The corporate and financing segment contributed $1,510 million to earnings in 2003, including a special item of $2,230 million relating to the settlement of a long-running U.S. tax dispute. Excluding this special item, corporate and financing expenses were down $241 million mainly due to lower U.S. pension expense.

2003

All other segments totaled a gain of $2,060 million in 2003 compared to a loss of $268 million in 2002.

Corporate and financing in 2003, including $2,230 million relating to the settlement of a long-running U.S. tax dispute, contributed $1,510 million to earnings. Excluding this settlement, corporate and financing expenses increased by $278 million mainly due to higher U.S. pension expense.

Net income in 2003 included a $550 million positive impact for the required adoption of FAS 143 relating to accounting for asset retirement obligations.

Merger-related activities were completed in 2002 and net income included $275 million of merger-related expenses. Net income in 2002 also included discontinued operations earnings of $449 million, including a gain associated with the sale of the Chilean copper business.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2004	2003
	(millions of dollars)	
Net cash provided by/(used in)		
Operating activities	$ 40,551	$ 28,498
Investing activities	(14,910)	(10,842)
Financing activities	(18,268)	(14,763)
Effect of exchange rate changes	532	504
Increase/(decrease) in cash and cash equivalents	$ 7,905	$ 3,397
	(Dec. 31)	
Cash and cash equivalents	$ 18,531	$ 10,626
Cash and cash equivalents – restricted	4,604	—
Total cash and cash equivalents	$ 23,135	$ 10,626

Cash and cash equivalents were $18,531 million at the end of 2004, an increase of $7,905 million, including $532 million of foreign exchange rate effects from the generally weaker U.S. dollar. Including restricted cash and cash equivalents of $4,604 million (see note 4 on page 57 and note 16 on page 70), total cash and cash equivalents of $23,135 million at the end of 2004 increased $12,509 million during the year. Cash and cash equivalents were $10,626 million at the end of 2003, an increase of $3,397 million, including $504 million of foreign exchange rate effects. Cash flows from operating, investing and financing activities are discussed below. For additional details, see the Consolidated Statement of Cash Flows on page 53.

Although the Corporation issues long-term debt from time to time and maintains a revolving commercial paper program, internally generated funds cover the majority of its financial requirements. The management of cash that may be temporarily available as surplus to the Corporation's immediate needs is carefully controlled, both to optimize returns on cash balances, and to ensure that it is secure and readily available to meet the Corporation's cash requirements as they arise.

Production from existing oil and gas fields has declined about 6 percent on average over the past two years and is expected to continue to decline in the future at approximately the same rate. The impact on cash flows from production is highly dependent on crude oil and natural gas prices. Decline rates vary widely by individual field and the overall decline rate for a geographical area will be heavily influenced by the type of reservoir and age of the fields in that region.

The Corporation will need to continually find and develop new fields, and continue to develop and apply new technologies and recovery processes to existing fields, in order to maintain or increase production and resulting cash flows in future periods. The Corporation has been successful in offsetting the effects of field decline through these measures and anticipates similar results in the future. Projects are in place or under way to increase production capacity. However, these volume increases are subject to a variety of risks including project execution, operational outages, reservoir performance, price effects on production sharing contracts and regulatory changes.

The Corporation's financial strength, as evidenced by its AAA/Aaa debt rating, enables it to make large, long-term capital expenditures. ExxonMobil currently expects to spend approximately $12 billion annually through the end of the decade on Upstream capital and exploration expenditures. The Corporation has a large and diverse portfolio of development projects and exploration opportunities, which helps mitigate the overall political and technical risks of the Corporation's Upstream segment and associated cash flow. Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments. The purchase and sale of oil and gas properties have not had a significant impact on the amount or timing of operating cash flows.

Cash Flow from Operating Activities

2004

Cash provided by operating activities totaled $40.6 billion in 2004, a $12.1 billion increase from 2003. Major sources of funds were net income of $25.3 billion, which increased $3.8 billion, and noncash provisions of $9.8 billion for depreciation and depletion. Contributing to the increased level of cash provided by operating activities in 2004 was $2.4 billion of lower company contributions to pension plans and $3.0 billion of cash received related to the U.S. tax settlement recognized in earnings in 2003.

2003

Cash provided by operating activities totaled $28.5 billion in 2003, a $7.2 billion increase from 2002 influenced by higher net income. Major sources of funds were net income of $21.5 billion and noncash provisions of $9.0 billion for depreciation and depletion.

In 2003, ExxonMobil completed a divestment of interests in shares of Ruhrgas AG, a German gas transmission company. These shares were held in part by BEB Erdgas und Erdoel GmbH (BEB), an investment accounted for by the equity method, and in part by a consolidated affiliate in Germany. In 2002, cash in the amount of $1,466 million was received from BEB, an equity company, and included in cash flows from operating activities (see Ruhrgas transaction line on Consolidated Statement of Cash Flows, page 53). This cash from BEB was a loan and was part of a restructuring that enabled BEB to transfer its holdings in Ruhrgas AG provided regulatory approval was received. No income was recorded in 2002.

In 2003, upon receipt of regulatory approvals, the Ruhrgas AG shares held by BEB were transferred, cash was received for the shares held by the consolidated affiliate and a one-time gain of $1,700 million after tax was recognized in net income. The $2,240 million reduction in 2003 cash flow from operating activities reflects the pretax gains from the transaction. The cash generated from these gains for the BEB portion of the transaction was reported in 2002. For the shares held by the consolidated affiliate, the cash received was reported in cash flows from investing activities in 2003.

Cash Flow from Investing Activities

2004

Cash used in investing activities totaled $14.9 billion in 2004, $4.1 billion higher than 2003. Spending for property, plant and equipment decreased $0.9 billion. Proceeds from the sales of subsidiaries, investments and property, plant and equipment in 2004 increased $0.5 billion to $2.8 billion. As discussed in note 16 on page 70, investing activities in 2004 included a pledge by the Corporation of $4.6 billion of collateral consisting of cash and short-term, high-quality securities to the issuer of a litigation-related appeal bond. This collateral was reported as restricted cash and cash equivalents on the balance sheet.

2003

Cash used in investing activities totaled $10.8 billion in 2003, $1.0 billion higher than 2002. Spending for property, plant and equipment increased $1.4 billion, reflecting the Corporation's active investment program. Proceeds from the sales of subsidiaries, investments and property, plant and equipment in 2003 were $2.3 billion, including $1.2 billion from the sale of an interest in Ruhrgas AG partly held by a consolidated affiliate.

Cash Flow from Financing Activities

2004

Cash used in financing activities was $18.3 billion, an increase of $3.5 billion from 2003, reflecting a higher level of purchases of ExxonMobil shares. Dividend payments on common shares increased to $1.06 per share from $0.98 per share and totaled $6.9 billion, a payout of 27 percent. Total consolidated short-term and long-term debt declined $1.2 billion to $8.3 billion at year-end 2004. Shareholders' equity increased $11.8 billion in 2004 to $101.7 billion, reflecting $25.3 billion of net income partly offset by distributions to ExxonMobil shareholders of $6.9 billion of dividends and $9.0 billion of net purchases of shares of ExxonMobil stock. Shareholders' equity, and net assets and liabilities, also increased $2.2 billion, representing the foreign exchange translation effects of stronger foreign currencies on ExxonMobil's operations outside the U.S.

During 2004, Exxon Mobil Corporation purchased 218 million shares of its common stock for the treasury at a gross cost of $10.0 billion. These purchases were to offset shares issued in conjunction with company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,568 million at the end of 2003 to 6,401 million at the end of 2004. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2003

Cash used in financing activities was $14.8 billion, an increase of $3.4 billion from 2002, reflecting higher levels of debt reductions and purchases of ExxonMobil shares. Dividend payments on common shares increased to $0.98 per share from $0.92 per share and totaled $6.5 billion, a payout of 30 percent. Total consolidated short-term and long-term debt declined $1.2 billion to $9.5 billion at year-end 2003. Shareholders' equity increased $15.3 billion in 2003 to $89.9 billion, reflecting $21.5 billion of net income partly offset by $6.5 billion of dividends paid to ExxonMobil shareholders and $5.4 billion of net purchases of shares of ExxonMobil stock. Shareholders' equity, and net assets and liabilities, also increased $4.4 billion, representing the foreign exchange translation effects of stronger foreign currencies on ExxonMobil's operations outside the U.S.

During 2003, Exxon Mobil Corporation purchased 163 million shares of its common stock for the treasury at a gross cost of $5.9 billion. These purchases were to offset shares issued in conjunction with company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,700 million at the end of 2002 to 6,568 million at the end of 2003. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

Commitments

Set forth below is information about the Corporation's commitments outstanding at December 31, 2004. It provides data for easy reference from the consolidated balance sheet and from individual notes to the consolidated financial statements.

Commitments	Note Reference Number	Payments Due by Period 2005	2006-2009	2010 and Beyond	Total
		(millions of dollars)			
Long-term debt [1]	14	$ —	$ 666	$4,347	$5,013
– Due in one year [2]		608	—	—	608
Asset retirement obligations [3]	9	142	784	2,684	3,610
Pension obligations [4]	17	1,703	1,576	5,531	8,810
Operating leases [5]	10	1,323	2,813	1,855	5,991
Unconditional purchase obligations [6]	16	602	1,918	2,125	4,645
Take-or-pay obligations [7]		907	1,994	2,087	4,988
Firm capital commitments [8]		3,823	2,069	529	6,421

This table excludes commodity purchase obligations (volumetric commitments but no fixed or minimum price) for which an active, highly liquid market exists and which are expected to be resold shortly after purchase. Examples include long-term, noncancelable upstream commitments with equity companies to purchase Qatar LNG production and downstream offtake commitments with equity companies and third parties to purchase refinery products at market prices. Inclusion of such amounts would not be meaningful in assessing liquidity and cash flow, since such market-based purchases will be offset in the same periods by cash received from sales.

Notes:

(1) Includes capitalized lease obligations of $354 million. Long-term debt amounts exclude the Corporation's share of equity company debt, which is included in the calculation of return on average capital employed as shown on page 29.

(2) The amount due in one year is included in notes and loans payable of $3,280 million (note 6 on page 57).

(3) The discounted present value of upstream asset retirement obligations, primarily asset removal costs at the completion of field life.

(4) The amount by which accumulated benefit obligations (ABOs) exceeded the fair value of fund assets for certain U.S. and non-U.S. plans at year end (note 17 on page 72). For funded pension plans, this difference was $3.5 billion at December 31, 2004 (U.S. $0.9 billion, non-U.S. $2.6 billion). For unfunded plans, this was the ABO amount of $5.3 billion (U.S. $1.0 billion, non-U.S. $4.3 billion). The payments by period include expected contributions to funded pension plans in 2005 and estimated benefit payments for unfunded plans in all years.

(5) Minimum commitments for operating leases, shown on an undiscounted basis, cover drilling equipment, tankers, service stations and other properties.

(6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. The undiscounted obligations of $4,645 million mainly pertain to pipeline throughput agreements and include $2,513 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $1,386 million, was $3,259 million.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undiscounted obligations of $4,988 million mainly pertain to transportation, refining and natural gas purchases and include $503 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $1,046 million, totaled $3,942 million.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $6.4 billion. These commitments were predominantly associated with upstream projects outside the U.S., of which the largest single commitment outstanding at the end of 2004 was $1.6 billion associated with the development of crude oil and natural gas resources in Malaysia. The Corporation expects to fund the majority of these commitments through internal cash flow.

Guarantees

	Dec. 31, 2004 Equity Company Obligations	Other Third-Party Obligations	Total
		(millions of dollars)	
Guarantees of excise taxes/customs duties under reciprocal arrangements	$ —	$ 1,122	$1,122
Other guarantees	2,428	344	2,772
Total	$ 2,428	$ 1,466	$3,894

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2004, for $3,894 million, primarily relating to guarantees for notes, loans and performance under contracts (note 16 on page 71). This included $1,122 million representing guarantees of non-U.S. excise taxes and customs duties of other companies, entered into as a normal business practice, under reciprocal arrangements. Also included in this amount were guarantees by consolidated affiliates of $2,428 million, representing ExxonMobil's share of obligations of certain equity companies. The above-mentioned guarantees are not reasonably likely to have a material current or future effect on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Financial Strength

On December 31, 2004, unused credit lines for short-term financing totaled approximately $5.2 billion (note 6 on page 57).

The table below shows the Corporation's fixed-charge coverage and consolidated debt-to-capital ratios. The data demonstrate the Corporation's creditworthiness. Throughout this period, the Corporation's long-term debt securities maintained the top credit rating from both Standard and Poor's (AAA) and Moody's (Aaa), a rating it has sustained for 86 years.

	2004	2003	2002
Fixed-charge coverage ratio (times)	36.1	30.8	13.8
Debt to capital (percent)	7.3	9.3	12.2
Net debt to capital (percent) (1)	(10.7)	(1.2)	4.4
Credit rating	AAA/Aaa	AAA/Aaa	AAA/Aaa

(1) *Debt net of cash, excluding restricted cash. The ratio of net debt to capital including restricted cash is (16.3) percent for 2004.*

Management views the Corporation's financial strength, as evidenced by the above financial ratios and other similar measures, to be a competitive advantage of strategic importance. The Corporation's sound financial position gives it the opportunity to access the world's capital markets in the full range of market conditions, and enables the Corporation to take on large, long-term capital commitments in the pursuit of maximizing shareholder value.

In addition to the above commitments, the Corporation makes limited use of derivative instruments, which are discussed in Risk Management on page 40 and note 13 on page 63.

Litigation and Other Contingencies

As discussed in note 16 to the consolidated financial statements, a number of lawsuits, including class actions, were brought in various courts against Exxon Mobil Corporation and certain of its subsidiaries relating to the accidental release of crude oil from the tanker Exxon Valdez in 1989. The vast majority of the compensatory claims have been resolved. All of the punitive damage claims were consolidated in the civil trial that began in May 1994.

In that trial, on September 24, 1996, the United States District Court for the District of Alaska entered a judgment in the amount of $5 billion in punitive damages to a class composed of all persons and entities who asserted claims for punitive damages from the Corporation as a result of the Exxon Valdez grounding. ExxonMobil appealed the judgment. On November 7, 2001, the United States Court of Appeals for the Ninth Circuit vacated the punitive damage award as being excessive under the Constitution and remanded the case to the District Court for it to determine the amount of the punitive damage award consistent with the Ninth Circuit's holding. The Ninth Circuit upheld the compensatory damage award, which has been paid. On December 6, 2002, the District Court reduced the punitive damage award from $5 billion to $4 billion. Both the plaintiffs and ExxonMobil appealed that decision to the Ninth Circuit. The Ninth Circuit panel vacated the District Court's $4 billion punitive damage award without argument and sent the case back for the District Court to reconsider in light of the recent U.S. Supreme Court decision in *Campbell v. State Farm.* On January 28, 2004, the District Court reinstated the punitive damage award at $4.5 billion plus interest. ExxonMobil and the plaintiffs appealed the decision to the Ninth Circuit. The Corporation has posted a $5.4 billion letter of credit. Management believes that the likelihood of the judgment being upheld is remote. While it is reasonably possible that a liability may have been incurred arising from the Exxon Valdez grounding, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

On December 19, 2000, a jury in Montgomery County, Alabama, returned a verdict against the Corporation in a dispute over royalties in the amount of $88 million in compensatory damages and $3.4 billion in punitive damages in the case of *Exxon Corporation v. State of Alabama, et al.*The verdict was upheld by the trial court on May 4, 2001. On December 20, 2002, the Alabama Supreme Court vacated the $3.5 billion jury verdict. The case was retried and on November 14, 2003, a state district court jury in Montgomery, Alabama, returned a verdict against Exxon Mobil Corporation. The verdict included $63.5 million in compensatory damages and $11.8 billion in punitive damages. On March 29, 2004, the district court judge reduced the amount of punitive damages to $3.5 billion. ExxonMobil believes the judgment is not justified by the evidence, that any punitive damage award is not justified by either the facts or the law, and that the amount of the award is grossly excessive and unconstitutional. ExxonMobil has appealed the decision. Management believes that the likelihood of the judgment being upheld is remote. While it is reasonably possible that a liability may have been incurred by ExxonMobil from this dispute over royalties, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability. On May 4, 2004, the Corporation posted a $4.5 billion supersedeas bond as required by Alabama law to stay execution of the judgment pending appeal. The Corporation has pledged to the issuer of the bond collateral consisting of cash and short-term, high-quality securities with an aggregate value of approximately $4.6 billion. This collateral is reported as restricted cash and cash equivalents on the Consolidated Balance Sheet on page 51. Under the terms of the pledge agreement, the Corporation is entitled to receive the income generated from the cash and securities and to make investment decisions, but is restricted from using the pledged cash and securities for any other purpose until such time the bond is canceled.

On May 22, 2001, a state court jury in New Orleans, Louisiana, returned a verdict against the Corporation and three other entities in a case brought by a landowner claiming damage to his property. The property had been leased by the landowner to a company that performed pipe cleaning and storage services for customers, including the Corporation. The jury awarded the plaintiff $56 million in compensatory damages (90 percent to be paid by the Corporation) and $1 billion in punitive damages (all to be paid by the Corporation). The damage related to the presence of naturally occurring radioactive material (NORM) on the site resulting from pipe cleaning operations. The award has been upheld at the trial court. ExxonMobil has appealed the judgment to the Louisiana Fourth Circuit Court of Appeals and believes that the judgment should be set aside or substantially reduced on factual and constitutional grounds. Management believes that the likelihood of the judgment being upheld is remote. While it is reasonably possible that a liability may have been incurred by ExxonMobil from this dispute over property damages, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

In *Allapattah v. Exxon,* a jury in the United States District Court for the Southern District of Florida determined in January 2001 that a class of all Exxon dealers between March 1983 and August 1994 had been overcharged between 1.03 and 1.4 cents per gallon for gasoline. Exxon sold a total of 39.8 billion gallons of gasoline to its dealers during this period. The estimated value of the potential claims associated with the 39.8 billion gallons of gasoline is $494 million. Including related interest, the total is approximately $1.3 billion. On June 11, 2003, the Eleventh Circuit Court of Appeals affirmed the judgment and on March 15, 2004, denied a petition for Rehearing En Banc. On October 12, 2004, the U.S. Supreme Court granted review of an issue raised by ExxonMobil as to whether the class in the District Court judgment should include members that individually do not satisfy the $50,000 minimum amount-in-controversy requirement in federal court. Members of the class could file claims through December 1, 2004. Claims representing over 90 percent of the gallons have been filed. In light of the Supreme Court's decision to grant review of only part of ExxonMobil's appeal, ExxonMobil took an after-tax charge of $550 million in the third quarter reflecting the estimated liability, including interest and after considering potential set-offs and defenses, for the claims in excess of $50,000.

Tax issues for 1983 to 1993 remain pending before the U.S. Tax Court. The ultimate resolution of these issues is not expected to have a materially adverse effect upon the Corporation's operations or financial condition.

Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a materially adverse effect upon the Corporation's operations or financial condition. There are no events or uncertainties known to management beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

CAPITAL AND EXPLORATION EXPENDITURES

	2004		2003	
	U.S.	Non-U.S.	U.S.	Non-U.S.
	(millions of dollars)			
Upstream [1]	$ 1,922	$ 9,793	$ 2,125	$ 9,863
Downstream	775	1,630	1,244	1,537
Chemical	262	428	333	359
Other	66	9	64	—
Total	$ 3,025	$ 11,860	$ 3,766	$ 11,759

(1) *Exploration expenses included.*

Capital and exploration expenditures in 2004 were $14.9 billion, reflecting the Corporation's continued active investment program. Upstream spending was down 2 percent to $ 11.7 billion in 2004, from $ 12.0 billion in 2003, as a result of lower spending on major projects in the North Sea and the U.S. These decreases were partly offset by higher development drilling in Qatar, the Caspian and Russia. Capital and exploration expenditures are not tracked by the undeveloped and developed proved reserve categories. During the past three years, Upstream capital and exploration expenditures averaged $11.4 billion, and the Corporation currently expects to spend approximately $12 billion annually through the end of the decade. The majority of these expenditures are on major development projects, which typically take two to four years from the time of recording proved undeveloped reserves to the start of production from those reserves. The percentage of proved developed reserves has remained relatively stable over the past five years at over 60 percent of total proved reserves, indicating that proved reserves are consistently moved from undeveloped to developed status. Capital investments in the Downstream totaled $2.4 billion in 2004, down $0.4 billion from 2003, primarily reflecting reduced spending on low-sulfur motor fuels projects in North America. Total Chemical capital expenditures were essentially unchanged from 2003.

TAXES

	2004	2003	2002
		(millions of dollars)	
Income taxes	$15,911	$11,006	6,499
Excise taxes	27,263	$23,855	22,040
All other taxes and duties	43,605	40,107	35,746
Total	$86,779	$74,968	$64,285
Total effective tax rate	40.3%	36.4%	39.8%

2004

Income, excise and all other taxes totaled $86.8 billion in 2004, an increase of $ 11.8 billion, or 16 percent, from 2003. Income tax expense, both current and deferred, was $15.9 billion, $4.9 billion higher than 2003, reflecting higher pretax income in 2004. The effective tax rate was 40.3 percent in 2004, compared to 36.4 percent in 2003. Excluding the income tax effects in 2003 of the gain on the Ruhrgas AG share transfer and the settlement of a U.S. tax dispute, the effective rate in 2004 was similar to the prior year. During both periods, the Corporation continued to benefit from the favorable resolution of other tax-related issues. Excise and all other taxes and duties of $70.9 billion in 2004 increased $6.9 billion from 2003, reflecting higher prices and foreign exchange effects.

2003

Income, excise and all other taxes totaled $75.0 billion in 2003, an increase of $10.7 billion, or 17 percent, from 2002. Income tax expense, both current and deferred, was $11.0 billion, $4.5 billion higher than 2002, reflecting higher pretax income in 2003. The effective tax rate was 36.4 percent in 2003. Excluding the income tax effects of the 2003 gain on the Ruhrgas AG share transfer and settlement of a U.S. tax dispute, the effective rate in 2003 was similar to the prior year. During both periods, the Corporation continued to benefit from the favorable resolution of other tax-related issues. Excise and all other taxes and duties of $64.0 billion in 2003 increased $6.2 billion from 2002, reflecting higher prices and foreign exchange effects.

MERGER EXPENSES AND REORGANIZATION RESERVES

In association with the merger between Exxon and Mobil, $410 million pretax ($275 million after tax) of costs were recorded as merger-related expenses in 2002. Charges included separation expenses related to workforce reductions (approximately 8,200 employees at year-end 2002), plus implementation and merger closing costs. Merger-related expenses for the period 1999 to 2002 cumulatively totaled approximately $3.2 billion pretax. Reflecting the completion of merger-related activities, merger expenses were not reported in either 2003 or 2004.

The following table summarizes the activity in the reorganization reserves. The 2002 opening balance represents accruals for provisions taken in prior years.

	Opening Balance	Additions	Deductions	Balance at Year End
	(millions of dollars)			
2002	$ 197	$ 93	$ 189	$ 101
2003	101	—	53	48
2004	48	—	21	27

ASSET RETIREMENT OBLIGATIONS AND ENVIRONMENTAL COSTS

Asset Retirement Obligations

The methodology of accounting for asset retirement obligations was modified as of January 1, 2003, per FAS 143. The fair values of asset retirement obligations are recorded as liabilities on a discounted basis when they are incurred, which is typically at the time assets are installed, with an offsetting amount booked as additions to property, plant and equipment ($143 million for 2004). Over time, the liabilities are accreted for the increase in their present value, with this effect included in expenses ($136 million in 2004). Payments made for asset retirement obligations in 2004 were $201 million, and the ending balance of the obligations recorded on the balance sheet at December 31, 2004, totaled $3,610 million.

Environmental Costs

	2004	2003
	(millions of dollars)	
Capital expenditures	$ 1,073	$ 1,306
Included in expenses	1,781	1,497
Total	$ 2,854	$ 2,803

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on the air, water and ground. This includes a significant investment in refining technology to manufacture low-sulfur motor fuels and projects to reduce nitrogen oxide and sulfur oxide emissions. ExxonMobil's 2004 worldwide environmental costs for all such preventative and remediation steps were about $2.9 billion, of which $1.1 billion were capital expenditures and $1.8 billion were included in expenses. The total cost for such activities is expected to be about $3.0 billion in 2005 (with capital expenditures representing just over 40 percent of the total), and a similar amount is expected for 2006.

The Corporation accrues liabilities for environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for probable environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency has identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at these multiparty sites mitigates ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil's operations, financial condition or liquidity. Provisions made in 2004 for new environmental liabilities were $340 million ($275 million in 2003), included in the $1.8 billion of 2004 expenses noted above, and the balance sheet reflects accumulated liabilities of $643 million as of December 31, 2004, and $528 million as of December 31, 2003.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations [1]	2004	2003	2002
Crude oil and NGL ($/barrel)	$ 34.76	$ 26.66	$ 22.30
Natural gas ($/kcf)	4.48	3.98	2.65

(1) *Consolidated subsidiaries.*

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have been varied, tending at times to be offsetting. In the Upstream, based on the 2004 worldwide production levels, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $400 million annual after-tax effect on Upstream consolidated plus equity company earnings. Similarly, a $0.10 per kcf change in the worldwide average gas realization would have approximately a $200 million annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide a broad indicator of changes in the earnings experienced in any particular period.

In the very competitive downstream and chemical environments, earnings are primarily determined by margin capture rather than absolute price levels of products sold. Refining margins are a function of the difference between what a refiner pays for its raw materials (primarily crude oil) and the market prices for the range of products produced. These prices in turn depend on global and regional supply/demand balances, inventory levels, refinery operations, import/export balances and weather.

The global energy markets can give rise to extended periods in which market conditions are adverse to one or more of the Corporation's businesses. Such conditions, along with the capital-intensive nature of the industry and very long lead times associated with many of our projects, underscore the importance of maintaining a strong financial position. Management views the Corporation's financial strength, including the AAA and Aaa ratings of its long-term debt securities by Standard and Poor's and Moody's, as a competitive advantage.

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where such sales take place, they are the result of efficiencies and competitive advantages of integrated refinery/chemical complexes. Additionally, intersegment sales are market-related. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity and transportation capabilities. About 40 percent of the Corporation's intersegment sales are crude oil produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocks and finished products.

Although price levels of crude oil and natural gas may rise or fall significantly over the short to medium term due to political events, OPEC actions and other factors, industry economics over the long term

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

will continue to be driven by market supply and demand. Accordingly, the Corporation tests the viability of all of its assets based on long-term price projections. The Corporation's assessment is that its operations will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment and asset management programs. Investment opportunities are tested against a variety of market conditions, including low-price scenarios. As a result, investments that would succeed only in highly favorable price environments are screened out of the investment plan.

The Corporation has had an active asset management program in which underperforming assets are either improved to acceptable levels or considered for divestment. The asset management program involves a disciplined, regular review to ensure that all assets are contributing to the Corporation's strategic and financial objectives. The result has been the creation of a very efficient capital base and has meant that the Corporation has seldom been required to write down the carrying value of assets, even during periods of low commodity prices.

Risk Management

The Corporation's size, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses mitigate the Corporation's risk from changes in interest rates, currency rates and commodity prices. The Corporation relies on these operating attributes and strengths to reduce enterprise-wide risk. As a result, the Corporation makes limited use of derivatives to offset exposures arising from existing transactions.

The Corporation does not trade in derivatives nor does it use derivatives with leverage features. The Corporation maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity. The Corporation's derivative activities pose no material credit or market risks to ExxonMobil's operations, financial condition or liquidity. Interest rate, foreign exchange rate and commodity price exposures arising from derivative contracts undertaken in accordance with the Corporation's policies have not been significant.

Derivatives	**2004**	**2003**	**2002**
	(millions of dollars)		
Net receivable/(payable)	$ 6	$(17)	$ 20
Net gain/(loss), before tax	38	$ 4	(35)

The fair values of derivatives outstanding and recorded on the balance sheet are shown in the table above. This is the amount that the Corporation would have paid to or received from third parties if these derivatives had been settled. These derivative fair values were substantially offset by the fair values of the underlying exposures being hedged. The gains/losses before tax include the offsetting amounts from the changes in fair value of the items being hedged by the derivatives. The fair value of derivatives outstanding at year-end 2004 and gain recognized during the year are immaterial in relation to the Corporation's year-end cash balance of $18.5 billion, total assets of $195.3 billion or net income for the year of $25.3 billion.

Debt-Related Instruments

The Corporation is exposed to changes in interest rates, primarily as a result of its short-term debt and long-term debt carrying floating interest rates. The Corporation makes limited use of interest rate swap agreements to adjust the ratio of fixed and floating rates in the debt portfolio. The impact of a 100-basis-point change in interest rates affecting the Corporation's debt would not be material to earnings, cash flow or fair value.

Foreign Currency Exchange Rate Instruments

The Corporation conducts business in many foreign currencies and is subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investment transactions. The impacts of fluctuations in foreign currency exchange rates on ExxonMobil's geographically diverse operations are varied and often offsetting in amount. The Corporation makes limited use of currency exchange contracts to reduce the risk of adverse foreign currency movements related to certain foreign currency debt obligations. Exposure from market-rate fluctuations related to these contracts is not material. Aggregate foreign exchange transaction gains and losses included in net income are discussed in note 4 on page 57.

Commodity Instruments

The Corporation makes limited use of commodity forwards, swaps and futures contracts of short duration to mitigate the risk of unfavorable price movements on certain crude, natural gas and petroleum product purchases and sales. Commodity price exposure related to these contracts is not material.

Inflation and Other Uncertainties

The general rate of inflation in most major countries of operation has been relatively low in recent years, and the associated impact on costs has been countered by cost reductions from efficiency and productivity improvements.

The operations and earnings of the Corporation and its affiliates throughout the world have been, and may in the future be, affected from time to time in varying degree by political developments and laws and regulations, such as forced divestiture of assets; restrictions on production, imports and exports; price controls; tax increases and retroactive tax claims; expropriation of property; cancellation of contract rights; and environmental regulations. Both the likelihood of such occurrences and their overall effect upon the Corporation vary greatly from country to country and are not predictable.

RECENTLY ISSUED STATEMENTS OF FINANCIAL ACCOUNTING STANDARDS

In December 2004, the Financial Accounting Standards Board (FASB) issued a revised Statement of Financial Accounting Standards No. 123 (FAS 123R), "Share-based Payment." FAS 123R requires compensation costs related to share-based payments to be recognized in the income statement over the vesting period. The amount of the compensation cost will be measured based on the grant-date fair value of the instrument issued. FAS 123R is effective as of July 1, 2005, for all awards granted or modified after that date and for those awards granted prior to that date that have not vested. FAS 123R will have no earnings impact on the Corporation because in 2003 the Corporation adopted a policy of expensing all share-based payments that is consistent with the provisions of FAS 123R, and all prior year outstanding awards have vested.

EMERGING ACCOUNTING AND REPORTING ISSUES

Accounting for Suspended Well Costs

At its September 2004 meeting, the Emerging Issues Task Force (EITF) discussed Issue No. 04-9, “Accounting for Suspended Well Costs.” Statement of Financial Accounting Standards No. 19 (FAS 19), “Financial Accounting and Reporting by Oil and Gas Producing Companies,” requires costs of drilling exploratory wells to be capitalized pending determination of whether the well has found proved reserves. If the well has found proved reserves, the capitalized costs are included in wells, equipment and facilities. If, however, the well has not found proved reserves, the capitalized costs of drilling the well are expensed, net of any salvage value, within one year except under certain specific circumstances. Questions have arisen in practice about the application of this guidance. The EITF agreed to remove this issue from the EITF agenda and requested that the FASB consider an amendment to FAS 19 to address this issue. On February 4, 2005, the FASB issued a proposed FASB Staff Position (FSP) that would amend FAS 19 to permit the continued capitalization of exploratory well costs beyond one year if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. Comments on the FSP are due back to the FASB in March 2005, and the guidance in the FSP would be applied prospectively in the first reporting period beginning after the FSP is finalized.

ExxonMobil continues to carry as an asset the cost of drilling exploratory wells that find sufficient quantities of reserves to justify their completion as producing wells if the required capital expenditure is made and drilling of additional exploratory wells is under way or firmly planned for the near future. Once exploration activities demonstrate that sufficient quantities of commercially producible reserves have been discovered, continued capitalization is dependent on project reviews, which take place at least annually, to ensure that sufficient progress toward ultimate development of the reserves is being achieved. Exploratory well costs not meeting these criteria are charged to expense. ExxonMobil does not believe that this issue will have a material impact on its financial statements.

The following table shows the amount of suspended wells on the year-end balance sheet that were greater than one year old with no firm exploratory drilling planned.

	Dec. 31 2004	Dec. 31 2003
	(millions of dollars)	
Projects greater than one year old with no firm exploratory drilling planned	$ 718	$ 693
Total suspended well cost	1,070	1,093

Accounting for Purchases and Sales of Inventory with the Same Counterparty

At its November 2004 meeting, the EITF began discussion of Issue No. 04-13, “Accounting for Purchases and Sales of Inventory with the Same Counterparty.” This Issue addresses the question of when it is appropriate to measure purchases and sales of inventory at fair value and record them in cost of sales and revenues and when they should be recorded as an exchange measured at the book value of the item sold. The EITF did not reach a consensus on this issue, but requested the FASB staff to further explore the alternative views.

ExxonMobil records certain crude oil, natural gas, petroleum product, and chemical purchases and sales of inventory entered into contemporaneously with the same counterparty as cost of sales and revenues, measured at fair value as agreed upon by a willing buyer and a willing seller. These transactions occur under contractual arrangements that establish the agreement terms either jointly, in a single contract, or separately, in individual contracts. This accounting treatment is consistent with long-term, predominant industry practice based on the Corporation’s knowledge of the industry (although the Corporation understands that some companies in the oil and gas industry may be accounting for these transactions differently as nonmonetary exchanges). Should the EITF reach a consensus on this Issue requiring these transactions to be recorded as exchanges measured at book value, the Corporation’s accounts “Sales and other operating revenue” and “Crude oil and product purchases” on the Consolidated Statement of Income would be lower by equal amounts with no impact on net income. All operating segments would be impacted by this change, but the largest effects are in the Downstream. The Corporation has not yet determined the amount by which “Sales and other operating revenue” and “Crude oil and product purchases” would be lower under this interpretation. A special effort is needed to accumulate this information manually since heretofore it has never been necessary to identify these monetary transactions separately from other monetary purchases and monetary sales. A best efforts estimate based on this undertaking is expected to be available in the second quarter of 2005. The Corporation does not believe this estimate will be material, but if it is, the information will be disclosed once it is available together with material changes in trends and uncertainties, if any.

CRITICAL ACCOUNTING POLICIES

The Corporation’s accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbon-based products. The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The following summary provides further information about the critical accounting policies and the judgments that are made by the Corporation in the application of those policies.

Oil and Gas Reserves

Evaluations of oil and gas reserves are important to the effective management of upstream assets. They are integral to making investment decisions about oil and gas properties such as whether development should proceed or enhanced recovery methods should be undertaken. Oil and gas reserve quantities are also used as the basis of calculating the unit-of-production rates for depreciation and evaluating for impairment. Oil and gas reserves are divided between proved and unproved reserves. Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions; i.e., prices and costs as of the date the estimate is made. Unproved reserves are those with less than reasonable certainty of recoverability and are classified as either probable or possible. Probable reserves are reserves that are more likely to be recovered than not, and possible reserves are less likely to be recovered than not.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations and extrapolations of well information such as flow rates and reservoir pressure declines. In certain deepwater fields, proved reserves are recorded in a limited number of cases before flow tests are conducted because of the safety and cost implications of conducting the tests. In those situations, other industry-accepted analyses are used such as information from well logs, a thorough pressure and fluid sampling program, conventional core data obtained across the entire reservoir interval and nearby analog data. Historically, proved reserves recorded using these methods have been immaterial when compared to the Corporation's total proved reserves and have also been validated by subsequent flow tests or actual production levels. Furthermore, the Corporation only records proved reserves for projects that have received significant funding commitments by management made toward the development of the reserves.

The estimation of proved reserves is controlled by the Corporation through long-standing approval guidelines. Reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals (assisted by a central reserves group with significant technical experience) culminating in reviews with and approval by senior management. Notably, no employee is compensated based on the level of proved reserve bookings.

Key features of the reserves estimation process include:

- rigorous peer-reviewed technical evaluations and analysis of well and field performance information (such as flow rates and reservoir pressure declines), and
- a requirement that management make significant funding commitments toward the development of the reserves prior to booking.

Although the Corporation is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in long-term oil and gas price levels.

Proved reserves can be further subdivided into developed and undeveloped reserves. The percentage of proved developed reserves has remained relatively stable over the past five years at over 60 percent of total proved reserves (including both consolidated and equity reserves), indicating that proved reserves are consistently moved from undeveloped to developed status. Management is not aware of any factors that would significantly change this historical relationship in the next several years. Over time, these undeveloped reserves will be reclassified to the developed category as new wells are drilled, existing wells are recompleted and/or facilities to collect and deliver the production from existing and future wells are installed. Major development projects typically take two to four years from the time of recording proved reserves to the start of production from these reserves.

Based on regulatory guidance, the Corporation has reported 2004 reserves on the basis of December 31, 2004, prices and costs ("year-end prices"). Resultant changes from the year-end 2003 reserve estimates, which were based on long-term projections of oil and gas prices consistent with those used in the Corporation's investment decision-making process, are shown in the line titled "Year-end price/cost revisions" on pages 83 and 84.

The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments will be required based on prices occurring on a single day. The Corporation believes that this approach is inconsistent with the long-term nature of the upstream business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the Corporation and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

Performance-related revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of (1) already available geologic, reservoir or production data or (2) new geologic, reservoir or production data. This category can also include changes associated with the performance of improved recovery projects and significant changes in either development strategy or production equipment/facility capacity.

The Corporation uses the "successful efforts" method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method for each field. The Corporation uses this accounting policy instead of the "full cost" method because it provides a more timely accounting of the success or failure of the Corporation's exploration and production activities. If the full cost method were used, all costs would be capitalized and depreciated on a country-by-country basis. The capitalized costs would be subject to an impairment test by country. The full cost method would tend to delay the expense recognition of unsuccessful projects.

Impact of Oil and Gas Reserves on Depreciation. The calculation of unit-of-production depreciation is a critical accounting estimate that measures the depreciation of upstream assets. It is the ratio of (1) actual volumes produced to (2) total proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods) applied to the (3) asset cost. The volumes produced and asset cost are known and, while proved developed reserves have a high probability of recoverability, they are based on estimates that are subject to some variability. This variability has generally resulted in net upward revisions of proved reserves in existing fields, as more information becomes available through research and actual production levels. While the upward revisions the Corporation has made in the past are an indicator of variability, they have had a very small impact on the unit-of-production rates because they have been small compared to the large reserves base.

Impact of Oil and Gas Reserves and Prices on Testing for Impairment. Proved oil and gas properties held and used by the Corporation are reviewed for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

The Corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In general, analyses are based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. An asset would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount by which the carrying value exceeds its fair value.

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses monitor the performance of assets against corporate objectives. They also assist the Corporation in assessing whether the carrying amounts of any of its assets may not be recoverable. In addition to estimating oil and gas reserve volumes in conducting these analyses, it is also necessary to estimate future oil and gas prices. The impairment evaluation triggers include a significant decrease in current and projected prices or reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected, and historical and current negative operating losses.

In general, the Corporation does not view temporarily low oil prices as a triggering event for conducting the impairment tests. The markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop precipitously, industry prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus demand will determine industry prices over the long term and these cannot be accurately predicted. Accordingly, any impairment tests that the Corporation performs make use of the Corporation's long-term price assumptions for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used in the Corporation's annual planning and budgeting processes and are also used for capital investment decisions. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Annual volumes are based on individual field production profiles, which are also updated annually. Prices for natural gas and other products are based on corporate plan assumptions developed annually by major region and used for investment evaluation purposes. Cash flow estimates for impairment testing exclude the use of derivative instruments.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves can be found on pages 78 to 85. The standardized measure of discounted future cash flows on pages 86 and 87 is based on the year-end 2004 price applied for all future years, as required under Statement of Financial Accounting Standards No. 69 (FAS 69). Future prices used for any impairment tests will vary from the one used in the FAS 69 disclosure, and could be lower or higher for any given year.

Suspended Exploratory Well Costs

The Corporation carries as an asset the cost of drilling exploratory wells that find sufficient quantities of reserves to justify their completion as producing wells if the required capital expenditure is made and drilling of additional exploratory wells is under way or firmly planned for the near future. Once exploration activities demonstrate that sufficient quantities of commercially producible reserves have been discovered, continued capitalization is dependent on project reviews, which take place at least annually, to ensure that sufficient progress toward ultimate development of the reserves is being achieved. Exploratory well costs not meeting these criteria are charged to expense.

The following table summarizes the year-end suspended exploratory well balances:

Exploration Suspended Drilling Costs	2004	2003
	(millions of dollars)	
Projects with drilling in past 12 months[(1)]	$ 207	$ 324
Projects with future exploratory drilling planned	145	76
Other exploratory activities planned	16	34
Subtotal – Projects with recent drilling or planned exploratory activity	368	434
Projects requiring major capital expenditures	621	519
Other projects progressing toward commercialization	81	140
Subtotal – Projects with completed exploratory activity	702	659
Total	$ 1,070	$ 1,093
Number of wells at year end	142	189

(1) *Includes $68 million for 2004 and $107 million for 2003 for wells older than one year on projects with additional exploratory drilling in the past 12 months as part of an overall exploration program to evaluate the property.*

The category "Other exploratory activities planned" includes wells whose continuing commercialization is dependent upon the results of additional seismic work that is either under way or planned. Significant advances in subsurface evaluation technologies have eliminated the need to drill as many exploratory wells as were required when FAS 19 was adopted in the late 1970s. The use of high-resolution 3-D seismic is a cost-effective technology that can eliminate the need for additional drilling in further defining the resource potential of a property.

The "Projects requiring major capital expenditures" category represents wells that require large capital projects (the Corporation's share of development costs typically greater than $50 million, excluding developmental drilling) to develop significant amounts of hydrocarbon resources discovered by these wells. Sufficient quantities of hydrocarbons have been discovered to justify a project. The timing for progressing these major projects to development is dependent upon factors such as lengthy negotiations with host governments, distance from markets and existing infrastructure, the effective deployment of existing technology, negotiations with joint venture partners on development plans and negotiations of long-term sales contracts, particularly if the reserves are in natural gas. These development activities are necessary to confirm whether the wells have found reserves that can be classified as proved, and often involve interfaces with a wide variety of regulatory bodies at the local, state and/or national level. In many cases required government approvals of proposed development plans have already been obtained, while in other cases development plan approvals are pending while the Corporation satisfies other regulatory requirements to maintain our rights to the resources.

The "Other projects progressing to commercialization" category includes both discoveries made near existing or already planned infrastructure, where the timing of development is driven by pipeline or facility capacity limitations, and smaller developments whose project timing is driven by negotiations with governments and co-venturers or the structuring of volume commitments under long-term sales contracts. In both cases, the existence of sufficient quantities of hydrocarbons to justify a project has been established, and deferral of well costs is a function of development timing.

The Corporation has a long history of converting exploration discoveries into successful projects and continued to progress activity on the suspended wells in 2004. Timing of proved reserve bookings will vary by individual project but the active, ongoing engagement of the Corporation's Upstream organization to progress these opportunities is our standard practice. The following table provides further detail on wells included in the "Projects requiring major capital expenditures" and "Other projects progressing toward commercialization" categories:

Country/Project	2004	Year-End 2004 Wells	Years Wells Drilled	Anticipated Year of Proved Reserve Booking	Comment
	(millions of dollars)				
Angola					
– Clochas/Tchihumba	$ 20	2	2003	2008 - 2009	Development awaiting capacity in existing infrastructure.
– Marimba	11	1	2001	2009 - 2010	Development in progress on first phase of Marimba deepwater project with proved reserves booked; development of second phase awaiting capacity in existing/planned infrastructure.
– Mavacola	12	2	2001 - 2002	2007 - 2008	Development awaiting capacity in existing/planned infrastructure; planned subsea tieback to floating production system; submission of Declaration of Commerciality anticipated in 2005.
– Mondo/Saxi/Batuque	26	4	2000 - 2002	2005 - 2006	Planned subsea tieback to floating production system; initial project funding in 2003.
– Orquidea/Violeta	6	2	1999 - 2001	2007 - 2008	Planned subsea tieback to floating production system; high-resolution 3-D seismic survey in 2004; submission of Declaration of Commerciality anticipated in 2005.
Australia					
– Gorgon/Jansz	73	17	1980 - 2003	2006 - 2007	Gorgon and Jansz resources to be developed as integrated LNG project; land access rights for onshore plant secured; negotiations with partners on unitized development plan are in progress.
– Kipper/Other	10	3	1986 - 2001	2005 - 2006	Bass Strait project in design phase and progressing toward funding; planned tie-in to existing platform.
Bolivia					
– Itau	38	2	1999 - 2001	2008 - 2009	Changes in hydrocarbon law that would impact development of the Itau resource have been proposed and are being debated in Bolivian legislature; resolution required before a development plan can be finalized.
Canada					
– Hebron	32	2	1999 - 2000	2007 - 2008	Actively working development concept with co-venturer; recent efforts focused on further technical evaluation of wells and reservoir using seismic reprocessing and well core analysis.
– Terra Nova	4	1	2001	2005 - 2006	Finalizing drilling plans to develop far east area of field in 2005.

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Country/Project	2004	Year-End 2004 Wells	Years Wells Drilled	Anticipated Year of Proved Reserve Booking	Comment
	(millions of dollars)				
Indonesia					
– Cepu	46	6	1998 - 2001	2005 - 2006	Negotiations with government to extend license term are in progress; initial project funding and engineering began in 2001 with timely development anticipated upon conclusion of negotiations.
– Natuna	118	4	1981 - 1983	2009 - 2010	Intent to proceed to the next phase of development communicated to government in 2004; discussions with government on near-term development work plans are in progress.
Nigeria					
– Etoro-Isobo	9	2	2002	2010 - 2011	Satellite development offshore Nigeria which will tie back to an existing production facility.
– Other	16	5	2001 - 2002	2007 - 2012	Actively pursuing development of several smaller offshore satellite discoveries, which will tie back to existing production facilities.
Norway					
– Fram	22	3	1991 - 1997	2005 - 2006	Initial project funding began in 2003 and initial design work was completed in 2004; first production anticipated in 2006.
– Lavrans	22	3	1995 - 1999	2016 - 2017	Development awaiting capacity in existing/planned infrastructure; planned subsea tieback to existing floating production system.
– Skarv/Snadd	24	5	1998 - 2001	2007 - 2008	Assessment of export infrastructure alternatives and negotiations with partners on development plan are in progress; submission of Plan of Development anticipated in 2005.
– Other	10	5	1992 - 2002	2005 - 2008	Progressing several smaller developments expected to result in proved reserve additions over next few years.
Papua New Guinea					
– Hides	35	2	1993 - 1998	2006 - 2007	Early engineering studies complete; negotiations with customers on sales terms are in progress; initial project funding and front-end engineering and design began in 2004.
Russia					
– Sakhalin 1, Phase 3	26	4	1996 - 1998	2010 - 2011	Actively progressing the third phase of the Sakhalin 1 project to utilize capacity in facilities and infrastructure in Phase 1. Phase 1 development under way with first production anticipated in 2005.
United Kingdom					
– Merganser	13	3	1995	2005 - 2006	Development awaiting capacity in existing infrastructure; planned subsea tieback to existing U.K. North Sea facilities.
– Puffin	42	4	1981 - 1986	2007 - 2008	Development awaiting capacity in existing infrastructure; planned tieback to existing U.K. North Sea production facility.
– Other	24	4	2001 - 2003	2005 - 2007	Several smaller projects whose development timing is governed by capacity availability in existing infrastructure.
United States					
– Point Thomson	28	2	1977 - 1980	2006 - 2007	Annual Plan of Development work program approved by state; initial engineering design for gas cycling option complete; also progressing alternate development options including tie-in to proposed Alaska gas pipeline.
Other					
– Various	35	10	1979 - 2003	2005 - 2015	
Total	$702	98			

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The timing of when proved reserves will be booked on the projects noted above is an estimate and subject to the uncertainties discussed under the heading "Factors Affecting Future Results" in Item 1 of ExxonMobil's 2004 Form 10-K. Actual results could differ from estimates due to the factors noted in Item 1.

The following table shows the amount of suspended well costs that were written off in the past three years after the Corporation made the decision that projects were not commercially viable and proved reserves would not be booked. Total exploration expenses, including nonconsolidated interests, are also shown to provide context on the suspended well write-offs.

	2004	2003	2002
		(millions of dollars)	
Suspended well write-offs	$ 98	$ 238	$ 22
Total exploration expense	1,133	1,033	957

Consolidations

The consolidated financial statements include the accounts of those significant subsidiaries that the Corporation controls. They also include the Corporation's undivided interests in upstream assets and liabilities. Amounts representing the Corporation's percentage interest in the underlying net assets of other significant affiliates that it does not control, but exercises significant influence, are included in "Investments and advances"; the Corporation's share of the net income of these companies is included in the consolidated statement of income caption "Income from equity affiliates." The accounting for these nonconsolidated companies is referred to as the equity method of accounting.

Majority ownership is normally the indicator of control that is the basis on which subsidiaries are consolidated. However, certain factors may indicate that a majority-owned investment is not controlled and therefore should be accounted for using the equity method of accounting. These factors occur where the minority shareholders are granted by law or by contract substantive participating rights. These include the right to approve operating policies, expense budgets, financing and investment plans and management compensation and succession plans.

The Corporation consolidates certain affiliates identified as variable-interest entities in which it has less than a majority ownership, because of guarantees or other arrangements that create majority economic interests in those affiliates that are greater than the Corporation's voting interests.

Additional disclosures of summary balance sheet and income information for those subsidiaries accounted for under the equity method of accounting can be found in note 7 on page 58. The Corporation believes this to be important information necessary to a full understanding of the Corporation's financial statements.

Investments in companies that are partially owned by the Corporation are integral to the Corporation's operations. In some cases they serve to balance worldwide risks and in others they provide the only available means of entry into a particular market or area of interest. The other parties who also have an equity interest in these companies are either independent third parties or host governments that share in the business results according to their percentage ownership. The Corporation does not invest in these companies in order to remove liabilities from its balance sheet. In fact, the Corporation has long been on record supporting an alternative accounting method that would require each investor to consolidate its percentage share of all assets and liabilities in these partially owned companies rather than only the percentage in the net equity. This method of accounting for investments in partially owned companies is not permitted by GAAP except where the investments are in the direct ownership of a share in the upstream assets and liabilities. However, for purposes of calculating return on average capital employed, which is not covered by GAAP standards, the Corporation includes its share of debt of these partially owned companies in the determination of average capital employed.

Annuity Benefits

The Corporation and its affiliates sponsor approximately 100 defined-benefit (pension) plans in about 50 countries. The funding arrangement for each plan depends on the prevailing practices and regulations of the countries where the Corporation operates. Note 17, pages 72 to 75, provides details on pension obligations, fund assets and pension expense.

Some of these plans (primarily non-U.S.) provide pension benefits that are paid directly by their sponsoring affiliates out of corporate cash flow rather than a separate pension fund. Book reserves are established for these plans because tax conventions and regulatory practices do not encourage advance funding. The portion of the pension cost attributable to employee service is expensed as services are rendered. The portion attributable to the increase in pension obligations due to the passage of time is expensed over the term of the obligations, which ends when all benefits are paid. The primary difference in pension expense for unfunded versus funded plans is that pension expense for funded plans also includes a credit for the expected long-term return on fund assets.

For funded plans, including many in the U.S., pension obligations are financed in advance through segregated assets or insurance arrangements. These plans are managed in compliance with the requirements of governmental authorities, and meet or exceed required funding levels as measured by relevant actuarial and government standards at the mandated measurement dates. In determining liabilities and required contributions, these standards often require approaches and assumptions that differ from those used for accounting purposes. Contributions to funded plans totaled $473 million in 2004 (all non-U.S.).

The Corporation will continue to make contributions to these funded plans as necessary. All defined-benefit pension obligations, regardless of the funding status of the underlying plans, are fully supported by the financial strength of the Corporation or the respective sponsoring affiliate.

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations, and the long-term rate for future salary increases. All the pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted only as appropriate to reflect changes in market rates and outlook. For example, the long-term expected earnings rate on U.S. pension plan assets in 2004 was 9.0 percent. This compares to an actual rate of return over the past decade of 12.5 percent. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the pension fund earnings rate would increase annual pension expense by approximately $85 million before tax.

Under GAAP, differences between actual returns on fund assets versus the long-term expected return are not recorded in the year that the difference occurs, but rather are amortized in pension expense, along with other actuarial gains and losses, over the expected remaining service life of employees.

Due to the general increase in the market value of pension assets, pension expense declined from $1,938 million in 2003 (U.S. $1,015 million, non-U.S. $923 million) to $1,630 million in 2004 (U.S. $764 million, non-U.S. $866 million).

Litigation and Other Contingencies

A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits and tax disputes. These are summarized on pages 37 and 38, with a more extensive discussion included in note 16 on pages 70 and 71.

GAAP requires that liabilities for contingencies be recorded when it is probable that a liability has been incurred by the date of the balance sheet and that the amount can be reasonably estimated. These amounts are not reduced by amounts that may be recovered under insurance or claims against third parties, but undiscounted receivables from insurers or other third parties may be accrued separately. The Corporation revises such accruals in light of new information.

Significant management judgment is required related to contingent liabilities and the outcome of litigation because both are difficult to predict. However, the Corporation has been successful in defending litigation in the past, and actual payments have not been material. In the Corporation's experience, large claims often do not result in large awards. Large awards are often reversed or substantially reduced as a result of appeal or settlement.

Foreign Currency Translation

The method of translating the foreign currency financial statements of the Corporation's international subsidiaries into U.S. dollars is prescribed by GAAP. Under these principles, it is necessary to select the functional currency of these subsidiaries. The functional currency is the currency of the primary economic environment in which the subsidiary operates. Management selects the functional currency after evaluating this economic environment. Downstream and chemical operations normally use the local currency, except in highly inflationary countries, primarily Latin America, as well as in Singapore, which uses the U.S. dollar, because it predominantly sells into the U.S. dollar export market. Upstream operations also use the local currency as the functional currency, except where crude and natural gas production is predominantly sold in the export market in U.S. dollars. These operations, which use the U.S. dollar as their functional currency, are in Malaysia, Indonesia, Angola, Nigeria, Equatorial Guinea and the Middle East.

Factors considered by management when determining the functional currency for a subsidiary include: the currency used for cash flows related to individual assets and liabilities; the responsiveness of sales prices to changes in exchange rates; whether sales are into local markets or exported; the currency used to acquire raw materials, labor, services and supplies; sources of financing; and significance of intercompany transactions.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation's chief executive officer, principal accounting officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2004.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31,2004, was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Lee R. Raymond Chief Executive Officer	Patrick T. Mulva Vice President and Controller (Principal Accounting Officer)	Donald D. Humphreys Vice President and Treasurer (Principal Financial Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PRICEWATERHOUSECOOPERS

To the Shareholders of Exxon Mobil Corporation:

We have completed an integrated audit of Exxon Mobil Corporation's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004, and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, shareholders' equity and cash flows appearing on pages 50 to 77 present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidiaries at December 31, 2004, and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in note 9 to the consolidated financial statements, the Corporation changed its method of accounting for asset retirement obligations in 2003.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Corporation maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Corporation's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Dallas, Texas
February 28, 2005

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2004	2003	2002
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue [1]		$291,252	$237,054	$200,949
Income from equity affiliates	7	4,961	4,373	2,066
Other income		1,822	5,311	1,491
Total revenues and other income		$298,035	$246,738	$204,506
Costs and other deductions				
Crude oil and product purchases		$139,224	$107,658	$ 90,950
Production and manufacturing expenses		23,225	21,260	17,831
Selling, general and administrative expenses		13,849	13,396	12,356
Depreciation and depletion		9,767	9,047	8,310
Exploration expenses, including dry holes		1,098	1,010	920
Merger-related expenses	3	—	—	410
Interest expense		638	207	398
Excise taxes [1]	19	27,263	23,855	22,040
Other taxes and duties	19	40,954	37,645	33,572
Income applicable to minority and preferred interests		776	694	209
Total costs and other deductions		$256,794	$214,772	$186,996
Income before income taxes		$ 41,241	$ 31,966	$ 17,510
Income taxes	19	15,911	11,006	6,499
Income from continuing operations		$ 25,330	$ 20,960	$ 11,011
Discontinued operations, net of income tax	2	—	—	449
Cumulative effect of accounting change, net of income tax		—	550	—
Net income		$ 25,330	$ 21,510	$ 11,460
Net income per common share *(dollars)*	12			
Income from continuing operations		$ 3.91	$ 3.16	$ 1.62
Discontinued operations, net of income tax		—	—	0.07
Cumulative effect of accounting change, net of income tax		—	0.08	—
Net income		$ 3.91	$ 3.24	$ 1.69
Net income per common share – assuming dilution *(dollars)*	12			
Income from continuing operations		$ 3.89	$ 3.15	$ 1.61
Discontinued operations, net of income tax		—	—	0.07
Cumulative effect of accounting change, net of income tax		—	0.08	—
Net income		$ 3.89	$ 3.23	$ 1.68

[1] *Sales and other operating revenue includes excise taxes of $27,263 million for 2004, $23,855 million for 2003 and $22,040 million for 2002.*

The information on pages 54 through 77 is an integral part of these statements.

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CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2004	Dec. 31 2003
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		$ 18,531	$ 10,626
Cash and cash equivalents – restricted	4, 16	4,604	—
Notes and accounts receivable, less estimated doubtful amounts	6	25,359	24,309
Inventories			
Crude oil, products and merchandise	1	8,136	7,665
Materials and supplies		1,351	1,292
Prepaid taxes and expenses		2,396	2,068
Total current assets		$ 60,377	$ 45,960
Investments and advances	8	18,404	15,535
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	108,639	104,965
Other assets, including intangibles, net		7,836	7,818
Total assets		$195,256	$174,278
Liabilities			
Current liabilities			
Notes and loans payable	6	$ 3,280	$ 4,789
Accounts payable and accrued liabilities	6	31,763	28,445
Income taxes payable		7,938	5,152
Total current liabilities		$ 42,981	$ 38,386
Long-term debt	14	5,013	4,756
Annuity reserves	17	10,850	9,609
Accrued liabilities		6,279	5,283
Deferred income tax liabilities	19	21,092	20,118
Deferred credits and other long-term obligations		3,333	2,829
Equity of minority and preferred shareholders in affiliated companies		3,952	3,382
Total liabilities		$ 93,500	$ 84,363
Commitments and contingencies	16		
Shareholders' equity			
Benefit plan related balances		$ (1,014)	$ (634)
Common stock without par value (9,000 million shares authorized)		5,067	4,468
Earnings reinvested		134,390	115,956
Accumulated other nonowner changes in equity			
Cumulative foreign exchange translation adjustment		3,598	1,421
Minimum pension liability adjustment		(2,499)	(2,446)
Unrealized gains/(losses) on stock investments		428	511
Common stock held in treasury (1,618 million shares in 2004 and 1,451 million shares in 2003)		(38,214)	(29,361)
Total shareholders' equity		$101,756	$ 89,915
Total liabilities and shareholders' equity		$195,256	$174,278

The information on pages 54 through 77 is an integral part of these statements.

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CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

	Note Reference Number	2004 Shareholders' Equity	2004 Nonowner Changes in Equity	2003 Shareholders' Equity	2003 Nonowner Changes in Equity	2002 Shareholders' Equity	2002 Nonowner Changes in Equity
				(millions of dollars)			
Benefit plan related balances							
At beginning of year		$ (634)		$ (450)		$ (159)	
Restricted stock award		(555)		(358)		(361)	
Amortization		173		107		11	
Other		2		67		59	
At end of year		$ (1,014)		$ (634)		$ (450)	
Common stock	12						
At beginning of year		4,468		4,217		3,789	
Issued		—		—		—	
Other		599		251		428	
At end of year		$ 5,067		$ 4,468		$ 4,217	
Earnings reinvested							
At beginning of year		115,956		100,961		95,718	
Net income for the year		25,330	$ 25,330	21,510	$ 21,510	11,460	$ 11,460
Dividends – common shares		(6,896)		(6,515)		(6,217)	
At end of year		$ 134,390		$ 115,956		$ 100,961	
Accumulated other nonowner changes in equity							
At beginning of year		(514)		(6,054)		(6,590)	
Foreign exchange translation adjustment		2,177	2,177	4,436	4,436	2,932	2,932
Minimum pension liability adjustment	17	(53)	(53)	514	514	(2,425)	(2,425)
Unrealized gains/(losses) on stock investments		(83)	(83)	590	590	29	29
At end of year		$ 1,527		$ (514)		$ (6,054)	
Total			$ 27,371		$ 27,050		$ 11,996
Common stock held in treasury							
At beginning of year		(29,361)		(24,077)		(19,597)	
Acquisitions, at cost		(9,951)		(5,881)		(4,798)	
Dispositions		1,098		597		318	
At end of year		$ (38,214)		$ (29,361)		$ (24,077)	
Shareholders' equity at end of year		$ 101,756		$ 89,915		$ 74,597	

		Share Activity 2004	Share Activity 2003	Share Activity 2002
			(millions of shares)	
Common stock				
Issued	12			
At beginning of year		8,019	8,019	8,019
Issued		—	—	—
At end of year		8,019	8,019	8,019
Held in treasury	12			
At beginning of year		(1,451)	(1,319)	(1,210)
Acquisitions		(218)	(163)	(127)
Dispositions		51	31	18
At end of year		(1,618)	(1,451)	(1,319)
Common shares outstanding at end of year		6,401	6,568	6,700

The information on pages 54 through 77 is an integral part of these statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2004	2003	2002
			(millions of dollars)	
Cash flows from operating activities				
Net income				
Accruing to ExxonMobil shareholders		$ 25,330	$ 21,510	$ 11,460
Accruing to minority and preferred interests		776	694	209
Cumulative effect of accounting change, net of income tax		—	(550)	—
Adjustments for noncash transactions				
Depreciation and depletion		9,767	9,047	8,310
Deferred income tax charges/(credits)		(1,134)	1,827	297
Annuity provisions		886	(1,489)	(500)
Accrued liability provisions		806	264	(90)
Dividends received greater than/(less than) equity in current earnings of equity companies		(1,643)	(402)	(170)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) – Notes and accounts receivable		(472)	(1,286)	(305)
– Inventories		(223)	(100)	353
– Prepaid taxes and expenses		11	42	32
Increase/(reduction) – Accounts and other payables		6,333	1,130	365
Ruhrgas transaction	5	—	(2,240)	1,466
All other items – net		114	51	(159)
Net cash provided by operating activities		$ 40,551	$ 28,498	$ 21,268
Cash flows from investing activities				
Additions to property, plant and equipment		$(11,986)	$(12,859)	$(11,437)
Sales of subsidiaries, investments and property, plant and equipment	5	2,754	2,290	2,793
Increase in restricted cash and cash equivalents	4,16	(4,604)	—	—
Additional investments and advances		(2,287)	(809)	(2,012)
Collection of advances		1,213	536	898
Net cash used in investing activities		$(14,910)	$(10,842)	$ (9,758)
Cash flows from financing activities				
Additions to long-term debt		$ 470	$ 127	$ 396
Reductions in long-term debt		(562)	(914)	(246)
Additions to short-term debt		450	715	751
Reductions in short-term debt		(2,243)	(1,730)	(927)
Additions/(reductions) in debt with less than 90-day maturity		(66)	(322)	(281)
Cash dividends to ExxonMobil shareholders		(6,896)	(6,515)	(6,217)
Cash dividends to minority interests		(215)	(430)	(169)
Changes in minority interests and sales/(purchases) of affiliate stock		(215)	(247)	(161)
Common stock acquired		(9,951)	(5,881)	(4,798)
Common stock sold		960	434	299
Net cash used in financing activities		$(18,268)	$(14,763)	$(11,353)
Effects of exchange rate changes on cash		$ 532	$ 504	$ 525
Increase/(decrease) in cash and cash equivalents		$ 7,905	$ 3,397	$ 682
Cash and cash equivalents at beginning of year		10,626	7,229	6,547
Cash and cash equivalents at end of year		$ 18,531	$ 10,626	$ 7,229

The information on pages 54 through 77 is an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements and the supporting and supplemental material are the responsibility of the management of Exxon Mobil Corporation.

The Corporation's principal business is energy, involving the worldwide exploration, production, transportation and sale of crude oil and natural gas (Upstream) and the manufacture, transportation and sale of petroleum products (Downstream). The Corporation is also a major worldwide manufacturer and marketer of petrochemicals (Chemical), and participates in electric power generation (Upstream).

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Certain reclassifications to prior years have been made to conform to the 2004 presentation.

1. Summary of Accounting Policies

Principles of Consolidation. The consolidated financial statements include the accounts of those significant subsidiaries owned directly or indirectly with more than 50 percent of the voting rights held by the Corporation, and for which other shareholders do not possess the right to participate in significant management decisions. They also include the Corporation's share of the undivided interest in upstream assets and liabilities. Additionally, the Corporation consolidates certain affiliates identified as variable-interest entities in which it has less than a majority ownership, because of guarantees or other arrangements that create majority economic interests in those affiliates that are greater than the Corporation's voting interests.

Amounts representing the Corporation's percentage interest in the underlying net assets of other significant subsidiaries and less-than-majority-owned companies in which a significant equity ownership interest is held, are included in "Investments and advances"; the Corporation's share of the net income of these companies is included in the consolidated statement of income caption "Income from equity affiliates." The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in consolidated shareholder's equity. Evidence of loss in value that might indicate impairment of investments in companies accounted for on the equity method is assessed to determine if such evidence represents a loss in value of the Corporation's investment that is other than temporary. Examples of key indicators include a history of operating losses, a negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, and the financial condition and prospects for the investee's business segment or geographic region. If evidence of an other than temporary loss in fair value below carrying amount is determined, an impairment is recognized. In the absence of market prices for the investment, discounted cash flows are used to assess fair value.

Revenue Recognition. The Corporation generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments. In all cases, revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectibility is reasonably assured.

Revenues include the sales portion of certain crude oil, natural gas, petroleum product, and chemical transactions settled in cash where the Corporation contemporaneously negotiates purchases with the same counterparty under contractual arrangements that establish the agreement terms either jointly, in a single contract, or separately, in individual contracts. The purchases are recorded in crude oil and product purchases. These transactions are commonly called buy/sell transactions. Together with nonmonetary exchanges as well as independently transacted purchases and sales of crude oil and petroleum products, buy/sell transactions are used to ensure that the right crude oil is at the appropriate refineries at the right time and that the appropriate products are available to meet consumer demands. This activity is called balancing the supply system.

Each buy/sell transaction is composed of a separate purchase and a separate sale transaction and therefore is accounted for as any other independently transacted monetary purchase or sale. These monetary transactions are accounted for as cost of sales and revenues, measured at fair value as agreed upon by a willing buyer and a willing seller. They are entered into with our normal suppliers and customers for substantive business purposes and invoiced for the full fair value of the transaction. Physical delivery is required and each counterparty is legally liable for the full value of the shipment. Each separate transaction transfers title to the crude oil or petroleum product, and delivery is not conditioned on any other transaction. Each separate transaction is subject to the risk of loss, credit risk, environmental risk, and counterparty nonperformance risk. These transactions are undertaken by all operating segments, but the majority occur in the Downstream.

Accounting for the sales portion of buy/sell transactions in revenues, measured at fair value, has been the predominant industry practice for decades, based on the Corporation's knowledge of the industry. The characteristics of these transactions are indistinguishable from those of any other monetary sales transaction. This accounting practice has recently been addressed in EITF Issue No 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not Held for Trading Purposes as Defined in Issue No. 02-3." While Issue 03-11 addresses the issue of gross versus net classification for derivative instruments, it also provides guidance for buy/sell transactions that are not accounted for as derivative instruments. In Issue 03-11, the EITF concluded that the determination of whether contracts not held for trading purposes should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. In addition, indicators for gross revenue reporting provided in EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" are consistent with many of the characteristics found in buy/sell transactions. These indicators are useful in providing guidance to assist in the determination of the appropriate accounting policy. In the judgment of management, the relevant facts and circumstances support accounting for these transactions in revenues, measured at fair value. The Corporation does not believe that these buy/sell transactions fall under the scope of APB Opinion 29, "Accounting for Nonmonetary Transactions" because they are monetary transactions.

Revenues from the production of natural gas properties in which the Corporation has an interest with other producers are recognized on the basis of the Corporation's net working interest. Differences between actual production and net working interest volumes are not significant.

Derivative Instruments. The Corporation makes limited use of derivatives. Derivative instruments are not held for trading purposes nor do they have leverage features. When the Corporation does enter into derivative transactions, it is to offset exposures associated with interest rates, foreign currency exchange rates and hydrocarbon prices. The gains and losses resulting from the changes in fair value of these instruments are recorded in income, except when the instruments are designated as hedging the currency exposure of net investments in foreign subsidiaries, in which case they are recorded in the cumulative foreign exchange translation account, as part of shareholders' equity.

The gains and losses on derivative instruments that are designated as fair value hedges (i.e., those hedging the exposure to changes in the fair value of an asset or a liability or the changes in the fair value of a firm commitment) are offset by the gains and losses from the changes in fair value of the hedged items, which are also recognized in income. Most of these designated hedges are entered into at the same time that the hedged items are transacted; they are fully effective and in combination with the offsetting hedged items result in no net impact on income. In some situations, the Corporation has chosen not to designate certain immaterial derivatives used for hedging economic exposure as hedges for accounting purposes due to the excessive administrative effort that would be required to account for these items as hedging transactions. These derivatives are recorded on the balance sheet at fair value and the gains and losses arising from changes in fair value are recognized in income. All derivatives activity is immaterial.

Inventories. Crude oil, products and merchandise inventories are carried at the lower of current market value or cost (generally determined under the last-in, first-out method — LIFO). Inventory costs include expenditures and other charges (including depreciation) directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost. Inventories of materials and supplies are valued at cost or less.

Crude oil, products and merchandise as of year-end 2004 and 2003 consist of the following:

	2004	2003
	(billions of dollars)	
Petroleum products	$ 3.4	$ 3.2
Crude oil	2.3	2.2
Chemical products	2.1	1.9
Gas/other	0.3	0.4
Total	$ 8.1	$ 7.7

Property, Plant and Equipment. Depreciation, depletion and amortization, based on cost less estimated salvage value of the asset, are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

The Corporation uses the "successful efforts" method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Costs of productive wells and development dry holes are capitalized and amortized on the unit-of-production method for each field.

The Corporation continues to carry as an asset the cost of drilling exploratory wells that find sufficient quantities of reserves to justify their completion as producing wells if the required capital expenditure is made and drilling of additional exploratory wells is under way or firmly planned for the near future. Once exploration activities demonstrate that sufficient quantities of commercially producible reserves have been discovered, continued capitalization is dependent on project reviews, which take place at least annually, to ensure that sufficient progress toward ultimate development of the reserves is being achieved. Exploratory well costs not meeting these criteria are charged to expense.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves. Significant unproved properties are assessed for impairment individually and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. The cost of properties that are not individually significant are aggregated by groups and amortized over the average holding period of the properties of the groups. The valuation allowances are reviewed at least annually. Other exploratory expenditures, including geophysical costs, other dry hole costs and annual lease rentals, are expensed as incurred.

Unit-of-production depreciation is applied to property, plant and equipment, including capitalized exploratory drilling and development costs, associated with productive depletable extractive properties, all in the Upstream segment. Unit-of-production rates are based on proved developed reserves, which are oil, gas and other mineral reserves estimated to be recoverable from existing facilities using current operating methods. Additional oil and gas to be obtained through the application of improved recovery techniques is included when, or to the extent that, the requisite commercial-scale facilities have been installed and the required wells have been drilled.

Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

Production costs are expensed as incurred. Production involves lifting the oil and gas to the surface and gathering, treating, field processing and field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incurred to operate and maintain the Corporation's wells and related equipment and facilities. They become part of the cost of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labor costs to operate the wells and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and related equipment; and administrative expenses related to the production activity.

Gains on sales of proved and unproved properties are only recognized when there is no uncertainty about the recovery of costs applicable

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to any interest retained or where there is no substantial obligation for future performance by the Corporation. Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

Proved oil and gas properties held and used by the Corporation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets.

The Corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using annually updated corporate plan investment evaluation assumptions for crude oil commodity prices and foreign currency exchange rates. Annual volumes are based on individual field production profiles, which are also updated annually. Prices for natural gas and other products are based on corporate plan assumptions developed annually by major region and also for investment evaluation purposes. Cash flow estimates for impairment testing exclude derivative instruments. Impairment analyses are generally based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairment evaluation. Impairments are measured by the amount the carrying value exceeds the fair value.

Asset Retirement Obligations and Environmental Costs. The Corporation incurs retirement obligations for its upstream assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserves are produced. Over time, the liabilities are accreted for the change in present value. Asset retirement obligations are not recorded for downstream and chemical facilities, because such potential obligations cannot be measured since it is not possible to estimate the settlement dates.

Liabilities for environmental costs are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. These liabilities are not reduced by possible recoveries from third parties, and projected cash expenditures are not discounted.

Foreign Currency Translation. The "functional currency" for translating the accounts of the majority of downstream and chemical operations outside the U.S. is the local currency. Local currency is also used for upstream operations that are relatively self-contained and integrated within a particular country, such as in Canada, the United Kingdom, Norway and continental Europe. The U.S. dollar is used for operations in highly inflationary economies, in Singapore, which is predominantly export-oriented, and for some upstream operations, primarily in Malaysia, Indonesia, Angola, Nigeria, Equatorial Guinea and the Middle East. For all operations, gains or losses on remeasuring foreign currency transactions into functional currency are included in income.

Stock-Based Awards. Effective January 1, 2003, the Corporation adopted for all employee stock-based awards granted after that date, the recognition provisions of Statement of Financial Accounting Standards No. 123 (FAS 123), "Accounting for Stock-Based Compensation." In accordance with FAS 123, compensation expense for awards granted on or after January 1, 2003, will be measured by the fair value of the award at the date of grant and recognized over the vesting period. The fair value of awards in the form of restricted stock is the market price of the stock. The fair value of awards in the form of stock options is estimated using an option-pricing model.

The Corporation has retained its prior method of accounting for stock-based awards granted before January 1, 2003. Under this method, compensation expense for awards granted in the form of stock options is measured at the intrinsic value of the options (the difference between the market price of stock and the exercise price of the options) on the date of grant. Since these two prices are the same on the date of grant, no compensation expense was recognized in income for these awards. Additionally, compensation expense for awards granted in the form of restricted stock is based on the price of the stock when it is granted and is recognized over the vesting period, which is the same method of accounting as under FAS 123.

If the provisions of FAS 123 had been adopted for all prior years, the impact on compensation expense, net income, and net income per share would have been as follows:

	2004	2003	2002
	(millions of dollars)		
Net income, as reported	$25,330	$21,510	$11,460
Add: Stock-based compensation, net of tax included in reported net income	144	86	19
Deduct: Stock-based compensation, net of tax determined under fair-value-based method	(146)	(93)	(180)
Pro forma net income	$25,328	$21,503	$11,299
	(dollars per share)		
Net income per share:			
Basic – as reported	$ 3.91	$ 3.24	$ 1.69
Basic – pro forma	3.91	3.24	1.67
Diluted – as reported	3.89	3.23	1.68
Diluted – pro forma	3.89	3.23	1.66

The pro forma amounts that would have been reported if FAS 123 had been in effect for all years are based on the fair value of stock-based awards granted for each of those years and recognized over the vesting period. In 2004, 2003 and 2002, the stock-based awards were in the form of restricted common stock and restricted stock units, and the fair value is based on the price of the stock at the date of grant, which was $51.07, $36.11 and $34.64 in 2004, 2003 and 2002, respectively. No stock option awards were made in these years.

2. Discontinued Operations

In 2002, the copper business in Chile and the coal operations in Colombia were sold. Earnings of these businesses are reported as discontinued operations for 2002 as presented in the consolidated statement of income. Income taxes related to discontinued operations were $41 million in 2002. Included in discontinued operations for 2002 are gains on the dispositions of $400 million, net of tax. The assets sold were primarily property, plant and equipment in the amount of $1.3 billion. Revenues of these operations were not material. These businesses were historically reported in the "All Other" column in the segment disclosures located in note 18 on pages 75 and 76.

3. Merger Expenses and Reorganization Reserves

In association with the merger between Exxon and Mobil, $410 million pretax ($275 million after tax) of costs were recorded as merger-related expenses in 2002. Cumulative charges for the period 1999 to 2002 of $3,189 million included separation expenses of approximately $1,460 million related to workforce reductions (approximately 8,200 employees at year-end 2002), plus implementation costs and merger closing costs. Reflecting the completion of merger-related activities, merger expenses were not reported in 2003 or 2004.

The following table summarizes the activity in the reorganization reserves. The 2002 opening balance represents accruals for provisions taken in prior years.

	Opening Balance	Additions	Deductions	Balance at Year End
		(millions of dollars)		
2002	$ 197	$ 93	$ 189	$ 101
2003	101	—	53	48
2004	48	—	21	27

4. Miscellaneous Financial Information

Research and development costs totaled $649 million in 2004, $618 million in 2003 and $631 million in 2002.

Net income included aggregate foreign exchange transaction gains of $69 million in 2004 and $11 million in 2003, and losses of $106 million in 2002.

In 2004, 2003 and 2002, net income included gains of $227 million, $255 million and $159 million, respectively, attributable to the combined effects of LIFO inventory accumulations and draw-downs. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $9.8 billion and $6.8 billion at December 31, 2004, and 2003, respectively.

Restricted cash and cash equivalents were $4,604 million at December 31, 2004, attributable to cash and short-term, high-quality securities the Corporation pledged as collateral to the issuer of a $4.5 billion litigation-related bond. The Corporation posted this bond to stay execution of the judgment pending appeal in the case of *Exxon Corporation v. State of Alabama, et al.* (refer to page 37 and note 16 on page 70 for discussion of this lawsuit). Under the terms of the pledge agreement, the Corporation is entitled to receive the income generated from the cash and securities and to make investment decisions, but is restricted from using the pledged cash and securities for any other purpose until such time the bond is canceled.

5. Cash Flow Information

The consolidated statement of cash flows provides information about changes in cash and cash equivalents. Highly liquid investments with maturities of three months or less when acquired are classified as cash equivalents.

In 2003, ExxonMobil completed a divestment of interests in shares of Ruhrgas AG, a German gas transmission company. These shares were held in part by BEB Erdgas und Erdoel GmbH (BEB), an investment accounted for by the equity method, and in part by a consolidated affiliate in Germany. In 2002, cash in the amount of $1,466 million was received from BEB, an equity company, and included in cash flows from operating activities (see Ruhrgas transaction line on Consolidated Statement of Cash Flows, page 53). This cash from BEB was a loan and was part of a restructuring that enabled BEB to transfer its holdings in Ruhrgas AG, provided regulatory approval was received. No income was recorded in 2002.

In 2003, upon receipt of regulatory approvals, the Ruhrgas AG shares held by BEB were transferred, cash was received for the shares held by the consolidated affiliate and a one-time gain of $1,700 million after tax was recognized in net income. The $2,240 million reduction in 2003 cash flow from operating activities reflects the pretax gains from the transaction. The cash generated from these gains for the BEB portion of the transaction was reported in 2002. For the shares held by the consolidated affiliate, the cash received was reported in cash flows from investing activities in 2003.

Cash payments for interest were: 2004 – $328 million, 2003 – $429 million and 2002 – $437 million. Cash payments for income taxes were: 2004 – $13,510 million, 2003 – $8,149 million and 2002 – $6,106 million.

6. Additional Working Capital Information

	Dec. 31 2004	Dec. 31 2003
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $332 million and $358 million	$ 20,712	$ 16,766
Other, less reserves of $40 million and $38 million	4,647	7,543
Total	$ 25,359	$ 24,309
Notes and loans payable		
Bank loans	$ 839	$ 972
Commercial paper	1,491	1,579
Long-term debt due within one year	608	1,903
Other	342	335
Total	$ 3,280	$ 4,789
Accounts payable and accrued liabilities		
Trade payables	$ 18,186	$ 15,334
Payables to equity companies	1,871	1,584
Accrued taxes other than income taxes	6,055	5,374
Other	5,651	6,153
Total	$ 31,763	$ 28,445

On December 31, 2004, unused credit lines for short-term financing totaled approximately $5.2 billion. Of this total, $3.3 billion support commercial paper programs under terms negotiated when drawn. The weighted-average interest rate on short-term borrowings outstanding at December 31, 2004, and 2003 was 3.5 percent and 2.9 percent, respectively.

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7. Equity Company Information

The summarized financial information below includes amounts related to certain less-than-majority-owned companies and majority-owned subsidiaries where minority shareholders possess the right to participate in significant management decisions (see note 1 on page 54). These companies are primarily engaged in crude production, natural gas marketing and refining operations in North America; natural gas production, natural gas distribution and downstream operations in Europe; crude production in Kazakhstan and Abu Dhabi; and liquefied natural gas (LNG) operations in Qatar. Also included are several power generation, petrochemical/lubes manufacturing and chemical ventures. The Corporation's ownership in these ventures is in the form of shares in corporate joint ventures as well as interests in partnerships. The share of total revenues in the table below representing sales to ExxonMobil consolidated companies was 22 percent, 18 percent and 19 percent in the years 2004, 2003 and 2002, respectively.

Equity Company Financial Summary	2004 Total	2004 ExxonMobil Share	2003 Total	2003 ExxonMobil Share	2002 Total	2002 ExxonMobil Share
			(millions of dollars)			
Total revenues	$72,872	$ 26,359	$63,651	$ 23,667	$47,204	$ 17,230
Income before income taxes	$15,278	$ 6,141	$11,432	$ 5,356	$ 6,028	$ 2,844
Income taxes	3,257	1,180	1,871	983	1,461	778
Income from continuing operations	$12,021	$ 4,961	9,561	$ 4,373	$ 4,567	$ 2,066
Cumulative effect of accounting change, net of income tax	—	—	74	35	—	—
Net income	$12,021	$ 4,961	$ 9,635	$ 4,408	$ 4,567	$ 2,066
Current assets	$21,835	$ 7,803	$19,334	$ 7,386	$20,162	$ 7,658
Property, plant and equipment, less accumulated depreciation	46,236	15,793	40,895	15,034	39,351	14,254
Other long-term assets	6,600	4,166	5,820	2,694	5,524	2,614
Total assets	$74,671	$ 27,762	$66,049	$ 25,114	$65,037	$ 24,526
Short-term debt	$ 4,109	$ 1,348	$ 3,402	$ 1,336	$ 3,561	$ 1,443
Other current liabilities	14,463	5,397	13,394	5,112	15,529	5,991
Long-term debt	10,477	2,566	7,997	2,815	9,236	3,352
Other long-term liabilities	6,489	2,910	6,738	3,215	8,248	3,881
Advances from shareholders	12,339	3,799	11,092	3,091	10,721	2,927
Net assets	$26,794	$ 11,742	$23,426	$ 9,545	$17,742	$ 6,932

A list of significant equity companies as of December 31, 2004, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	
Aera Energy LLC	48
BEB Erdgas und Erdoel GmbH	50
Cameroon Oil Transportation Company S.A.	41
Castle Peak Power Company Limited	60
Nederlandse Aardolie Maatschappij B.V.	50
Qatar Liquefied Gas Company Limited	10
Ras Laffan Liquefied Natural Gas Company Limited	27
Ras Laffan Liquefied Natural Gas Company Limited II	30
Tengizchevroil, LLP	25
Downstream	
Chalmette Refining, LLC	50
Mineraloelraffinerie Oberrhein GmbH & Co. KG	25
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Infineum Holdings B.V.	50
Saudi Yanbu Petrochemical Co.	50

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8. Investments and Advances

	Dec. 31 2004	Dec. 31 2003
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	$ 11,742	$ 9,545
Advances	3,799	3,091
	$ 15,541	$ 12,636
Companies carried at cost or less and stock investments carried at fair value	1,931	1,795
	$ 17,472	$ 14,431
Long-term receivables and miscellaneous investments at cost or less	932	1,104
Total	$ 18,404	$ 15,535

9. Property, Plant and Equipment and Asset Retirement Obligations

	Dec. 31, 2004		Dec. 31, 2003	
Property, Plant and Equipment	**Cost**	**Net**	**Cost**	**Net**
	(millions of dollars)			
Upstream	$ 148,024	$ 62,013	$ 138,701	$ 58,727
Downstream	62,014	29,810	59,939	29,566
Chemical	21,777	10,049	20,623	10,115
Other	10,607	6,767	10,052	6,557
Total	$ 242,422	$ 108,639	$ 229,315	$ 104,965

In the Upstream segment, depreciation is on a unit-of-production basis, so depreciable life will vary by field. In the Downstream segment, investments in refinery and lubes basestock manufacturing facilities are generally depreciated on a straight-line basis over a 25-year life and service station buildings and fixed improvements over a 20-year life. In the Chemical segment, investments in process equipment are generally depreciated on a straight-line basis over a 20-year life.

Accumulated depreciation and depletion totaled $133,783 million at the end of 2004 and $124,350 million at the end of 2003. Interest capitalized in 2004, 2003 and 2002 was $500 million, $490 million and $426 million, respectively.

The Corporation carries as an asset the cost of drilling exploratory wells that find sufficient quantities of reserves to justify their completion as producing wells if the required capital expenditure is made and drilling of additional exploratory wells is under way or firmly planned or the near future. Once exploration activities demonstrate that sufficient quantities of commercially producible reserves have been discovered, continued capitalization is dependent on project reviews, which take place at least annually, to ensure that sufficient progress toward ultimate development of the reserves is being achieved. Exploratory well costs not meeting these criteria are charged to expense.

The following table provides the year-end balances and movements for suspended exploratory well costs:

	2004	2003	2002
	(millions of dollars)		
Beginning balance at January 1	$1,093	$1,193	$1,066
Additions to capitalized exploratory well costs pending the determination of proved reserves	139	217	195
Capitalized exploratory well costs charged to expense	(98)	(238)	(22)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(92)	(123)	(90)
Foreign exchange changes	28	44	44
Ending balance at December 31	$1,070	$1,093	$1,193
Number of wells at year end	142	189	204

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An aging of suspended well costs is shown below (Amounts – *millions of dollars)*:

	2004		2003		2002	
Age	**Amount**	**Wells**	**Amount**	**Wells**	**Amount**	**Wells**
< 1 Year	$ 139	14	$ 217	27	$ 195	42
1-5 Years	510	72	453	82	660	96
6-10 Years	172	32	162	49	102	36
> 10 Years	249	24	261	31	236	30
	$1,070	142	$1,093	189	$1,193	204

Asset Retirement Obligations (AROs)

As of January 1, 2003, the Corporation adopted Financial Accounting Standards Board Statement of Financial Accounting Standards No. 143 (FAS 143), "Accounting for Asset Retirement Obligations." The primary impact of FAS 143 was to change the method for accruing for upstream site restoration costs. Asset retirement obligations are not recorded for downstream and chemical facilities because such potential obligations cannot be measured since it is not possible to estimate the settlement dates.

Upstream costs were previously accrued ratably over the productive lives of the assets in accordance with Statement of Financial Accounting Standards No. 19 (FAS 19), "Financial Accounting and Reporting by Oil and Gas Producing Companies." Under FAS 143, the fair values of asset retirement obligations are recorded as liabilities on a discounted basis when they are incurred, which is typically at the time the assets are installed. Amounts recorded for the related assets will be increased by the amount of these obligations. Over time, the liabilities will be accreted for the change in their present value and the initial capitalized costs will be depreciated over the useful lives of the related assets.

The cumulative adjustment for the change in accounting principle reported in the first quarter of 2003 was after-tax income of $550 million (net of $442 million of income tax effects, including ExxonMobil's share of related equity company income taxes of $51 million), or $0.08 per common share. The effect of this accounting change on the 2003 balance sheet was a $0.3 billion increase to property, plant and equipment, a $0.6 billion reduction to the accrued liability and a $0.4 billion increase in deferred income tax liabilities

The following table summarizes the activity in the liability for asset retirement obligations:

	2004	2003
	(millions of dollars)	
Beginning balance	$ 3,440	$ 3,454
Cumulative effect of accounting change *(1)*	—	(622)
Accretion expense and other provisions	136	174
Payments made	(201)	(113)
Liabilities incurred	143	253
Foreign currency translation/other	92	294
Ending balance	$ 3,610	$ 3,440

(1) Cumulative Effect of 2003 Accounting Change	**2003**
	(millions of dollars)
Increase in net PP&E	$ 284
Decrease in ARO liability	622
Increase in deferred tax liability	(391)
Increase in investments in equity companies	35
Total after-tax earnings	$ 550

10. Leased Facilities

At December 31, 2004, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering drilling equipment, tankers, service stations and other properties with minimum lease commitments as indicated in the table.

Net rental expenditures for 2004, 2003 and 2002 totaled $2,491 million, $2,298 million and $2,322 million, respectively, after being reduced by related rental income of $136 million, $141 million and $140 million, respectively. Minimum rental expenditures totaled $2,501 million in 2004, $2,319 million in 2003 and $2,378 million in 2002.

	Minimum Commitment	Related Rental Income
	(millions of dollars)	
2005	$ 1,323	$ 52
2006	1,025	42
2007	762	37
2008	562	32
2009	464	29
2010 and beyond	1,855	30
Total	$ 5,991	$ 222

11. Employee Stock Ownership Plans

In 1989, the Exxon and Mobil employee stock ownership plan trusts borrowed $1,000 million and $800 million, respectively, to finance the purchase of shares of Exxon and Mobil stock. The trusts were merged in late 1999 to create the ExxonMobil leveraged employee stock ownership trust (ExxonMobil ESOP). The ExxonMobil ESOP is a constituent part of the ExxonMobil Savings Plan, which, effective February 8, 2002, is an employee stock ownership plan in its entirety.

Employees eligible to participate in the ExxonMobil Savings Plan may elect to participate in the ExxonMobil ESOP. Corporate contributions to the plan and dividends were used to make principal and interest payments on the ExxonMobil ESOP notes ($65 million outstanding as of December 31, 2002, which was fully paid in 2003). As corporate contributions and dividends were credited, common shares were allocated to participants' plan accounts. The Corporation's contribution to the ExxonMobil ESOP, representing the amount by which debt service exceeded dividends on shares held by the ExxonMobil ESOP, was $59 million and $86 million in 2003 and 2002, respectively. No contributions were made in 2004.

Accounting for the plans has followed the principles that were in effect for the respective plans when they were established. During the time that the guaranteed ESOP borrowing was outstanding, the borrowing was included in ExxonMobil's debt. The future compensation to be earned by employees was classified in shareholders' equity. No guaranteed debt was outstanding at year-end 2004, and there was no future compensation classified in shareholders' equity as all compensation was earned. Expense, net of the dividends used for debt service, was recognized as the debt was repaid and shares were earned by employees. The amount of compensation expense related to the plans and recorded by the Corporation was $32 million in 2003 and $122 million in 2002. No expense was incurred in 2004.

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12. Capital

The authorized common stock of the Corporation is 9 billion shares without par value. The table below summarizes the earnings per share calculations:

Net income per common share	**2004**	**2003**	**2002**
Income from continuing operations *(millions of dollars)*	$ 25,330	$ 20,960	$ 11,011
Weighted average number of common shares outstanding *(millions of shares)*	6,482	6,634	6,753
Net income per common share *(dollars)*			
Income from continuing operations	$ 3.91	$ 3.16	$ 1.62
Discontinued operations, net of income tax	—	—	0.07
Cumulative effect of accounting change, net of income tax	—	0.08	—
Net income	$ 3.91	$ 3.24	$ 1.69

Net income per common share – assuming dilution			
Income from continuing operations *(millions of dollars)*	$ 25,330	$ 20,960	$ 11,011
Weighted average number of common shares outstanding *(millions of shares)*	6,482	6,634	6,753
Effect of employee stock-based awards	37	28	50
Weighted average number of common shares outstanding – assuming dilution	6,519	6,662	6,803
Net income per common share *(dollars)*			
Income from continuing operations	$ 3.89	$ 3.15	$ 1.61
Discontinued operations, net of income tax	—	—	0.07
Cumulative effect of accounting change, net of income tax	—	0.08	—
Net income	$ 3.89	$ 3.23	$ 1.68
Dividends paid per common share *(dollars)*	$ 1.06	$ 0.98	$ 0.92

13. Financial Instruments and Derivatives

The fair value of financial instruments is determined by reference to various market data and other valuation techniques as appropriate. Long-term debt is the only category of financial instruments whose fair value differs materially from the recorded book value. The estimated fair value of total long-term debt, including capitalized lease obligations, at December 31, 2004, and 2003, was $5.9 billion and $5.6 billion, respectively, as compared to recorded book values of $5.0 billion and $4.8 billion.

The Corporation's size, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses mitigate the Corporation's risk from changes in interest rates, currency rates and commodity prices. The Corporation relies on these operating attributes and strengths to reduce enterprise-wide risk. As a result, the Corporation makes limited use of derivatives to offset exposures arising from existing transactions.

The Corporation does not trade in derivatives nor does it use derivatives with leveraged features. The Corporation maintains a system of controls that includes a policy covering the authorization, reporting and monitoring of derivative activity. The Corporation's derivative activities pose no material credit or market risks to ExxonMobil's operations, financial condition or liquidity. Interest rate, foreign exchange rate and commodity price exposures arising from derivative contracts undertaken in accordance with the Corporation's policies have not been significant.

The fair value of derivatives outstanding and recorded on the balance sheet was a net receivable of $6 million and a net payable of $17 million at year-end 2004 and 2003, respectively. This is the amount that the Corporation would have paid to or received from third parties if these derivatives had been settled. These derivative fair values were substantially offset by the fair values of the underlying exposures being hedged. The Corporation recognized a gain of $38 million, a gain of $4 million and a loss of $35 million related to derivative activity during 2004, 2003 and 2002, respectively. The gains/losses included the offsetting amounts from the changes in fair value of the items being hedged by the derivatives.

14. Long-Term Debt

At December 31, 2004, long-term debt consisted of $4,671 million due in U.S. dollars and $342 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $608 million, which matures within one year and is included in current liabilities. The amounts of long-term debt maturing, together with sinking fund payments required, in each of the four years after December 31, 2005, in millions of dollars, are: 2006 – $120, 2007 – $127, 2008 – $284 and 2009 – $135. Certain of the borrowings described may from time to time be assigned to other ExxonMobil affiliates. At December 31, 2004, the Corporation's unused long-term credit lines were not material.

Summarized long-term borrowings at year-end 2004 and 2003 were as shown in the adjacent table:

	2004	2003
	(millions of dollars)	
Exxon Capital Corporation [1]		
6.0% Guaranteed notes due 2005	$ —	$ 106
6.125% Guaranteed notes due 2008	160	160
SeaRiver Maritime Financial Holdings, Inc. [1]		
Guaranteed debt securities due 2006-2011 [2]	75	85
Guaranteed deferred interest debentures due 2012		
– Face value net of unamortized discount plus accrued interest	1,249	1,121
Mobil Producing Nigeria Unlimited		
8.625% notes due 2006	—	63
Mobil Corporation		
8.625% debentures due 2021	248	248
Mobil Services (Bahamas) Ltd.		
Variable notes due 2034 [3]	311	—
Industrial revenue bonds due 2007-2033 [4]	1,702	1,688
Other U.S. dollar obligations [5]	719	640
Other foreign currency obligations	195	275
Capitalized lease obligations [6]	354	370
Total long-term debt	$ 5,013	$ 4,756

(1) *Additional information is provided for these subsidiaries on pages 64 to 68.*

(2) *Average effective interest rate of 1.5% in 2004 and 1.2% in 2003.*

(3) *Average effective interest rate of 2.0% in 2004.*

(4) *Average effective interest rate of 1.8% in 2004 and 1.7% in 2003.*

(5) *Average effective interest rate of 6.0% in 2004 and 6.3% in 2003.*

(6) *Average imputed interest rate of 7.4% in 2004 and 7.0% in 2003.*

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Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

Exxon Mobil Corporation has fully and unconditionally guaranteed the 6.125% notes due 2008 ($160 million of long-term debt at December 31, 2004) of Exxon Capital Corporation and the deferred interest debentures due 2012 ($1,249 million long-term) and the debt securities due 2006 to 2011 ($75 million long-term and $10 million short-term) of SeaRiver Maritime Financial Holdings, Inc.

Exxon Capital Corporation and SeaRiver Maritime Financial Holdings, Inc. are 100-percent-owned subsidiaries of Exxon Mobil Corporation.

The following condensed consolidating financial information is provided for Exxon Mobil Corporation, as guarantor, and for Exxon Capital Corporation and SeaRiver Maritime Financial Holdings, Inc., as issuers, as an alternative to providing separate financial statements for the issuers. The accounts of Exxon Mobil Corporation, Exxon Capital Corporation and SeaRiver Maritime Financial Holdings, Inc. are presented utilizing the equity method of accounting for investments in subsidiaries.

	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)			
Condensed consolidated statement of income for 12 months ended December 31, 2004						
Revenues and other income						
Sales and other operating revenue, including excise taxes	$ 13,617	$ —	$ —	$ 277,635	$ —	$ 291,252
Income from equity affiliates	23,115	—	15	4,966	(23,135)	4,961
Other income	521	—	—	1,301	—	1,822
Intercompany revenue	24,147	33	22	196,653	(220,855)	—
Total revenues and other income	61,400	33	37	480,555	(243,990)	298,035
Costs and other deductions						
Crude oil and product purchases	23,217	—	—	324,920	(208,913)	139,224
Production and manufacturing expenses	6,642	3	—	21,945	(5,365)	23,225
Selling, general and administrative expenses	2,099	4	—	12,056	(310)	13,849
Depreciation and depletion	1,424	4	1	8,338	—	9,767
Exploration expenses, including dry holes	187	—	—	911	—	1,098
Merger-related expenses	—	—	—	—	—	—
Interest expense	1,381	21	135	5,339	(6,238)	638
Excise taxes	—	—	—	27,263	—	27,263
Other taxes and duties	14	—	—	40,940	—	40,954
Income applicable to minority and preferred interests	—	—	—	776	—	776
Total costs and other deductions	34,964	32	136	442,488	(220,826)	256,794
Income before income taxes	26,436	1	(99)	38,067	(23,164)	41,241
Income taxes	1,106	(1)	(40)	14,846	—	15,911
Income from continuing operations	25,330	2	(59)	23,221	(23,164)	25,330
Discontinued operations, net of income tax	—	—	—	—	—	—
Accounting change, net of income tax	—	—	—	—	—	—
Net income	$ 25,330	$ 2	$ (59)	$ 23,221	$ (23,164)	$ 25,330

	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)			
Condensed consolidated statement of income for 12 months ended December 31, 2003						
Revenues and other income						
Sales and other operating revenue, including excise taxes	$ 11,328	$ —	$ —	$ 225,726	$ —	$ 237,054
Income from equity affiliates	18,163	—	1	4,363	(18,154)	4,373
Other income	3,229	—	—	2,082	—	5,311
Intercompany revenue	17,918	33	19	142,930	(160,900)	—
Total revenues and other income	50,638	33	20	375,101	(179,054)	246,738
Costs and other deductions						
Crude oil and product purchases	17,342	—	—	240,908	(150,592)	107,658
Production and manufacturing expenses	6,492	2	1	19,691	(4,926)	21,260
Selling, general and administrative expenses	2,037	2	—	11,526	(169)	13,396
Depreciation and depletion	1,535	5	2	7,505	—	9,047
Exploration expenses, including dry holes	247	—	—	763	—	1,010
Merger-related expenses	—	—	—	—	—	—
Interest expense	648	21	121	4,629	(5,212)	207
Excise taxes	1	—	—	23,854	—	23,855
Other taxes and duties	9	—	—	37,636	—	37,645
Income applicable to minority and preferred interests	—	—	—	694	—	694
Total costs and other deductions	28,311	30	124	347,206	(160,899)	214,772
Income before income taxes	22,327	3	(104)	27,895	(18,155)	31,966
Income taxes	1,367	(1)	(37)	9,677	—	11,006
Income from continuing operations	20,960	4	(67)	18,218	(18,155)	20,960
Discontinued operations, net of income tax	—	—	—	—	—	—
Accounting change, net of income tax	550	—	—	481	(481)	550
Net income	$ 21,510	$ 4	$ (67)	$ 18,699	$ (18,636)	$ 21,510
Condensed consolidated statement of income for 12 months ended December 31, 2002						
Revenues and other income						
Sales and other operating revenue, including excise taxes	$ 8,711	$ —	$ —	$ 192,238	$ —	$ 200,949
Income from equity affiliates	10,177	—	(16)	2,048	(10,143)	2,066
Other income	580	5	—	906	—	1,491
Intercompany revenue	15,711	41	27	120,836	(136,615)	—
Total revenues and other income	35,179	46	11	316,028	(146,758)	204,506
Costs and other deductions						
Crude oil and product purchases	14,687	—	—	207,709	(131,446)	90,950
Production and manufacturing expenses	5,312	2	1	16,839	(4,323)	17,831
Selling, general and administrative expenses	1,592	2	—	10,898	(136)	12,356
Depreciation and depletion	1,572	5	3	6,730	—	8,310
Exploration expenses, including dry holes	147	—	—	773	—	920
Merger-related expenses	70	—	—	356	(16)	410
Interest expense	655	22	112	4,634	(5,025)	398
Excise taxes	—	—	—	22,040	—	22,040
Other taxes and duties	12	—	—	33,560	—	33,572
Income applicable to minority and preferred interests	—	—	—	209	—	209
Total costs and other deductions	24,047	31	116	303,748	(140,946)	186,996
Income before income taxes	11,132	15	(105)	12,280	(5,812)	17,510
Income taxes	121	6	(31)	6,403	—	6,499
Income from continuing operations	11,011	9	(74)	5,877	(5,812)	11,011
Discontinued operations, net of income tax	449	—	—	456	(456)	449
Accounting change, net of income tax	—	—	—	—	—	—
Net income	$ 11,460	$ 9	$ (74)	$ 6,333	$ (6,268)	$ 11,460

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)			
Condensed consolidated balance sheet for year ended December 31, 2004						
Cash and cash equivalents	$ 10,055	$ 4	$ —	$ 8,472	$ —	$ 18,531
Cash and cash equivalents – restricted	4,604	—	—	—	—	4,604
Notes and accounts receivable – net	3,262	—	—	22,097	—	25,359
Inventories	1,117	—	—	8,370	—	9,487
Prepaid taxes and expenses	79	—	—	2,317	—	2,396
Total current assets	19,117	4	—	41,256	—	60,377
Investments and advances	138,395	—	416	369,455	(489,862)	18,404
Property, plant and equipment – net	15,601	95	—	92,943	—	108,639
Other long-term assets	1,512	—	90	6,234	—	7,836
Intercompany receivables	9,728	1,090	1,594	322,469	(334,881)	—
Total assets	$ 184,353	$ 1,189	$ 2,100	$ 832,357	$ (824,743)	$ 195,256
Notes and loans payable	$ —	$ —	$ 10	$ 3,270	$ —	$ 3,280
Accounts payable and accrued liabilities	2,934	3	—	28,826	—	31,763
Income taxes payable	1,348	—	1	6,589	—	7,938
Total current liabilities	4,282	3	11	38,685	—	42,981
Long-term debt	261	160	1,324	3,268	—	5,013
Deferred income tax liabilities	3,152	28	268	17,644	—	21,092
Other long-term liabilities	5,461	22	—	18,931	—	24,414
Intercompany payables	69,441	185	403	264,852	(334,881)	—
Total liabilities	82,597	398	2,006	343,380	(334,881)	93,500
Earnings reinvested	134,390	6	(300)	81,380	(81,086)	134,390
Other shareholders' equity	(32,634)	785	394	407,597	(408,776)	(32,634)
Total shareholders' equity	101,756	791	94	488,977	(489,862)	101,756
Total liabilities and shareholders' equity	$ 184,353	$ 1,189	$ 2,100	$ 832,357	$ (824,743)	$ 195,256
Condensed consolidated balance sheet for year ended December 31, 2003						
Cash and cash equivalents	$ 5,647	$ —	$ —	$ 4,979	$ —	$ 10,626
Cash and cash equivalents – restricted	—	—	—	—	—	—
Notes and accounts receivable – net	5,781	—	—	18,528	—	24,309
Inventories	1,027	—	—	7,930	—	8,957
Prepaid taxes and expenses	91	—	—	1,977	—	2,068
Total current assets	12,546	—	—	33,414	—	45,960
Investments and advances	126,568	—	401	357,104	(468,538)	15,535
Property, plant and equipment – net	16,733	98	1	88,133	—	104,965
Other long-term assets	1,714	—	105	5,999	—	7,818
Intercompany receivables	9,463	1,114	1,540	381,683	(393,800)	—
Total assets	$ 167,024	$ 1,212	$ 2,047	$ 866,333	$ (862,338)	$ 174,278
Notes and loans payable	$ 1,104	$ —	$ 10	$ 3,675	$ —	$ 4,789
Accounts payable and accrued liabilities	3,538	6	—	24,901	—	28,445
Income taxes payable	1,457	—	—	3,695	—	5,152
Total current liabilities	6,099	6	10	32,271	—	38,386
Long-term debt	261	266	1,206	3,023	—	4,756
Deferred income tax liabilities	3,643	29	296	16,150	—	20,118
Other long-term liabilities	3,991	16	—	17,096	—	21,103
Intercompany payables	63,115	106	382	330,197	(393,800)	—
Total liabilities	77,109	423	1,894	398,737	(393,800)	84,363
Earnings reinvested	115,956	4	(241)	72,012	(71,775)	115,956
Other shareholders' equity	(26,041)	785	394	395,584	(396,763)	(26,041)
Total shareholders' equity	89,915	789	153	467,596	(468,538)	89,915
Total liabilities and shareholders' equity	$ 167,024	$ 1,212	$ 2,047	$ 866,333	$ (862,338)	$ 174,278

Condensed consolidated statement of cash flows for 12 months ended December 31, 2004	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)			
Cash provided by/(used in) operating activities	$ 21,515	$ 8	$ 44	$ 32,837	$ (13,853)	$ 40,551
Cash flows from investing activities						
Additions to property, plant and equipment	(1,101)	—	—	(10,885)	—	(11,986)
Sales of long-term assets	521	—	—	2,233	—	2,754
Increase in restricted cash and cash equivalents	(4,604)	—	—	—	—	(4,604)
Net intercompany investing	5,109	24	(55)	(5,224)	146	—
All other investing, net	2	—	—	(1,076)	—	(1,074)
Net cash provided by/(used in) investing activities	(73)	24	(55)	(14,952)	146	(14,910)
Cash flows from financing activities						
Additions to short- and long-term debt	—	—	—	920	—	920
Reductions in short- and long-term debt	(1,146)	(106)	(10)	(1,543)	—	(2,805)
Additions/(reductions) in debt with less than 90-day maturity	—	—	—	(66)	—	(66)
Cash dividends	(6,896)	—	—	(13,853)	13,853	(6,896)
Common stock acquired	(9,951)	—	—	—	—	(9,951)
Net intercompany financing activity	—	78	21	47	(146)	—
All other financing, net	959	—	—	(429)	—	530
Net cash provided by/(used in) financing activities	(17,034)	(28)	11	(14,924)	13,707	(18,268)
Effects of exchange rate changes on cash	—	—	—	532	—	532
Increase/(decrease) in cash and cash equivalents	$ 4,408	$ 4	$ —	$ 3,493	$ —	$ 7,905

Condensed consolidated statement of cash flows for 12 months ended December 31, 2003	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
Cash provided by/(used in) operating activities	$ 4,797	$ 23	$ 60	$ 24,945	$ (1,327)	$ 28,498
Cash flows from investing activities						
Additions to property, plant and equipment	(1,691)	—	—	(11,168)	—	(12,859)
Sales of long-term assets	238	—	—	2,052	—	2,290
Increase in restricted cash and cash equivalents	—	—	—	—	—	—
Net intercompany investing	13,555	281	(50)	(13,523)	(263)	—
All other investing, net	—	—	—	(273)	—	(273)
Net cash provided by/(used in) investing activities	12,102	281	(50)	(22,912)	(263)	(10,842)
Cash flows from financing activities						
Additions to short- and long-term debt	—	—	—	842	—	842
Reductions in short- and long-term debt	—	—	—	(2,644)	—	(2,644)
Additions/(reductions) in debt with less than 90-day maturity	—	(6)	(10)	(306)	—	(322)
Cash dividends	(6,515)	(93)	—	(1,234)	1,327	(6,515)
Common stock acquired	(5,881)	—	—	—	—	(5,881)
Net intercompany financing activity	—	(184)	—	(58)	242	—
All other financing, net	434	(21)	—	(677)	21	(243)
Net cash provided by/(used in) financing activities	(11,962)	(304)	(10)	(4,077)	1,590	(14,763)
Effects of exchange rate changes on cash	—	—	—	504	—	504
Increase/(decrease) in cash and cash equivalents	$ 4,937	$ —	$ —	$ (1,540)	$ —	$ 3,397

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

Condensed consolidated statement of cash flows for 12 months ended December 31, 2002	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)			
Cash provided by/(used in) operating activities	$ 1,970	$ 17	$ 69	$ 19,905	$ (693)	$ 21,268
Cash flows from investing activities						
Additions to property, plant and equipment	(1,727)	—	—	(9,710)	—	(11,437)
Sales of long-term assets	168	—	—	2,625	—	2,793
Increase in restricted cash and cash equivalents	—	—	—	—	—	—
Net intercompany investing	9,640	(30)	(59)	(9,646)	95	—
All other investing, net	—	—	—	(1,114)	—	(1,114)
Net cash provided by/(used in) investing activities	8,081	(30)	(59)	(17,845)	95	(9,758)
Cash flows from financing activities						
Additions to short- and long-term debt	—	—	—	1,147	—	1,147
Reductions in short- and long-term debt	—	—	(10)	(1,163)	—	(1,173)
Additions/(reductions) in debt with less than 90-day maturity	—	(29)	—	(252)	—	(281)
Cash dividends	(6,217)	—	—	(693)	693	(6,217)
Common stock acquired	(4,798)	—	—	—	—	(4,798)
Net intercompany financing activity	—	42	—	53	(95)	—
All other financing, net	299	—	—	(330)	—	(31)
Net cash provided by/(used in) financing activities	(10,716)	13	(10)	(1,238)	598	(11,353)
Effects of exchange rate changes on cash	—	—	—	525	—	525
Increase/(decrease) in cash and cash equivalents	$ (665)	$ —	$ —	$ 1,347	$ —	$ 682

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of award. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited or expire, or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Shares available for granting under the 2003 Incentive Program were 199,300 thousand at the end of 2004.

As under earlier programs, options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. Most of the options and SARs normally first become exercisable one year following the date of grant. All remaining stock options and SARs outstanding were granted prior to 2002.

Long-term incentive awards totaling 11,374 thousand, 10,381 thousand and 11,072 thousand shares of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2004, 2003 and 2002, respectively. These shares with a value of $554 million, $357 million and $361 million at the grant date in 2004, 2003 and 2002, respectively, will be issued to employees from treasury stock. The price of the stock on the date of grant was $51.07, $36.11 and $34.64 in 2004, 2003 and 2002, respectively. The total compensation expense of $581 million for 2004 grants (including units with a value of $27 million that will be settled in cash), of $375 million for 2003 grants (including units with a value of $18 million that will be settled in cash) and of $384 million for 2002 grants (including units with a value of $23 million that will be settled in cash) will be recognized over the vesting period. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares in each award vesting after three years and the remaining 50 percent vesting after seven years. A small number of awards granted to certain employees have longer vesting periods.

The following table summarizes information about restricted stock and restricted stock units, including those shares from former Mobil plans (shares in thousands):

Restricted Stock and Units	2004	2003	2002
Granted	11,374	10,381	11,072
Issued and outstanding at end of year	23,159	13,089	2,382

Changes that occurred in stock options in 2004, 2003 and 2002 are summarized below (shares in thousands):

	2004		2003		2002	
Stock Options	Shares	Avg. Exercise Price	Shares	Avg. Exercise Price	Shares	Avg. Exercise Price
Outstanding at beginning of year	223,750	$ 33.09	246,995	$ 31.59	265,695	$ 30.54
Exercised	(42,588)	22.57	(22,757)	16.80	(18,334)	16.18
Expired/canceled	(250)	39.91	(488)	35.86	(366)	40.47
Outstanding at end of year	180,912	35.55	223,750	33.09	246,995	31.59
Exercisable at end of year	180,912	35.55	222,054	33.06	243,548	31.46

The following table summarizes information about stock options outstanding at December 31, 2004 (shares in thousands):

Options Outstanding and Exercisable			
Exercise Price Range	Shares	Avg. Remaining Contractual Life	Avg. Exercise Price
$16.53 - 23.54	29,051	1.9 years	$ 22.12
25.36 - 37.12	86,782	5.0 years	34.00
40.07 - 45.22	65,079	5.4 years	43.62
Total	180,912	4.7 years	35.55

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

16. Litigation and Other Contingencies

Litigation

A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits and tax disputes. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. The Corporation does not record liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated, or when the liability is believed to be only reasonably possible or remote. ExxonMobil will continue to defend itself vigorously in these matters. Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a materially adverse effect upon the Corporation's operations or financial condition.

A number of lawsuits, including class actions, were brought in various courts against Exxon Mobil Corporation and certain of its subsidiaries relating to the accidental release of crude oil from the tanker Exxon Valdez in 1989. The vast majority of the compensatory claims have been resolved. All of the punitive damage claims were consolidated in the civil trial that began in May 1994.

In that trial, on September 24, 1996, the United States District Court for the District of Alaska entered a judgment in the amount of $5 billion in punitive damages to a class composed of all persons and entities who asserted claims for punitive damages from the Corporation as a result of the Exxon Valdez grounding. ExxonMobil appealed the judgment. On November 7, 2001, the United States Court of Appeals for the Ninth Circuit vacated the punitive damage award as being excessive under the Constitution and remanded the case to the District Court for it to determine the amount of the punitive damage award consistent with the Ninth Circuit's holding. The Ninth Circuit upheld the compensatory damage award, which has been paid. On December 6, 2002, the District Court reduced the punitive damage award from $5 billion to $4 billion. Both the plaintiffs and ExxonMobil appealed that decision to the Ninth Circuit. The Ninth Circuit panel vacated the District Court's $4 billion punitive damage award without argument and sent the case back for the District Court to reconsider in light of the recent U.S. Supreme Court decision in *Campbell v. State Farm.* On January 28, 2004, the District Court reinstated the punitive damage award at $4.5 billion plus interest. ExxonMobil and the plaintiffs have appealed the decision to the Ninth Circuit. The Corporation has posted a $5.4 billion letter of credit.

On January 29, 1997, a settlement agreement was concluded resolving all remaining matters between the Corporation and various insurers arising from the Valdez accident. Under terms of this settlement, ExxonMobil received $480 million. Final income statement recognition of this settlement continues to be deferred in view of uncertainty regarding the ultimate cost to the Corporation of the Valdez accident. Management believes that the likelihood of the judgment being upheld is remote. While it is reasonably possible that a liability may have been incurred arising from the Exxon Valdez grounding, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

On December 19, 2000, a jury in the 15th Judicial Circuit Court of Montgomery County, Alabama, returned a verdict against the Corporation in a dispute over royalties in the amount of $88 million in compensatory damages and $3.4 billion in punitive damages in the case of *Exxon Corporation v. State of Alabama, et al.*The verdict was upheld by the trial court on May 4, 2001. On December 20, 2002, the Alabama Supreme Court vacated the $3.5 billion jury verdict. The case was retried and on November 14, 2003, a state district court jury in Montgomery, Alabama, returned a verdict against Exxon Mobil Corporation. The verdict included $63.5 million in compensatory damages and $11.8 billion in punitive damages. On March 29, 2004, the district court judge reduced the amount of punitive damages to $3.5 billion. ExxonMobil believes the judgment is not justified by the evidence, that any punitive damage award is not justified by either the facts or the law, and that the amount of the award is grossly excessive and unconstitutional. ExxonMobil has appealed the decision. Management believes that the likelihood of the judgment being upheld is remote. While it is reasonably possible that a liability may have been incurred by ExxonMobil from this dispute over royalties, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability. On May 4, 2004, the Corporation posted a $4.5 billion supersedeas bond as required by Alabama law to stay execution of the judgment pending appeal. The Corporation has pledged to the issuer of the bond collateral consisting of cash and short-term, high-quality securities with an aggregate value of approximately $4.6 billion. This collateral is reported as restricted cash and cash equivalents on the Consolidated Balance Sheet on page 51. Under the terms of the pledge agreement, the Corporation is entitled to receive the income generated from the cash and securities and to make investment decisions, but is restricted from using the pledged cash and securities for any other purpose until such time the bond is canceled.

On May 22, 2001, a state court jury in New Orleans, Louisiana, returned a verdict against the Corporation and three other entities in a case brought by a landowner claiming damage to his property. The property had been leased by the landowner to a company that performed pipe cleaning and storage services for customers, including the Corporation. The jury awarded the plaintiff $56 million in compensatory damages (90 percent to be paid by the Corporation) and $1 billion in punitive damages (all to be paid by the Corporation). The damage related to the presence of naturally occurring radioactive material (NORM) on the site resulting from pipe cleaning operations. The award has been upheld at the trial court. ExxonMobil has appealed the judgment to the Louisiana Fourth Circuit Court of Appeals and believes that the judgment should be set aside or substantially reduced on factual and constitutional grounds. Management believes that the likelihood of the judgment being upheld is remote. While it is reasonably possible that a liability may have been incurred by ExxonMobil from this dispute over property damages, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

In *Allapattah v. Exxon,* a jury in the United States District Court for the Southern District of Florida determined in January 2001 that a class of all Exxon dealers between March 1983 and August 1994 had been overcharged between 1.03 and 1.4 cents per gallon for gasoline. Exxon sold a total of 39.8 billion gallons of gasoline to its dealers during this period. The estimated value of the potential claims associated with the 39.8 billion gallons of gasoline is $494 million. Including related interest, the total is approximately $1.3 billion. On June 11, 2003, the Eleventh Circuit Court of Appeals affirmed the judgment and on March 15, 2004, denied a petition for Rehearing En Banc. On October 12, 2004, the U.S. Supreme Court granted review of an issue raised by ExxonMobil as to whether the class in the District Court judgment should include members that individually do not satisfy the $50,000 minimum amount-in-controversy requirement in federal court. Members of the class could file claims through December 1, 2004. Claims representing over 90 percent of the gallons have been filed. In light of the Supreme Court's decision to grant review of only part of ExxonMobil's appeal, ExxonMobil took an after-tax charge of $550 million in the third quarter reflecting the estimated liability, including interest and after considering potential set-offs and defenses, for the claims in excess of $50,000.

Tax issues for 1983 to 1993 remain pending before the U.S. Tax Court. The ultimate resolution of these issues is not expected to have a materially adverse effect upon the Corporation's operations or financial condition.

Other Contingencies

	Dec. 31, 2004		
	Equity Company Obligations	Other Third-Party Obligations	Total
		(millions of dollars)	
Guarantees of excise taxes/customs duties under reciprocal arrangements	$ —	$ 1,122	$1,122
Other guarantees	2,428	344	2,772
Total	$ 2,428	$ 1,466	$3,894

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2004, for $3,894 million, primarily relating to guarantees for notes, loans and performance under contracts. This included $1,122 million representing guarantees of non-U.S. excise taxes and customs duties of other companies, entered into as a normal business practice, under reciprocal arrangements. Also included in this amount were guarantees by consolidated affiliates of $2,428 million, representing ExxonMobil's share of obligations of certain equity companies.

Additionally, the Corporation and its consolidated subsidiaries have numerous long-term sales and purchase commitments in their various business activities, all of which are expected to be fulfilled with no adverse consequences material to the Corporation's operations or financial condition. Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services.

	Payments Due by Period			
	2005	2006-2009	2010 and Beyond	Total
		(millions of dollars)		
Unconditional purchase obligations [1]	$602	$1,918	$2,125	$4,645

(1) *Undiscounted obligations of $4,645 million mainly pertain to pipeline throughput agreements and include $2,513 million of obligations to equity companies. The present value of these commitments, excluding imputed interest of $1,386 million, totaled $3,259 million.*

The operations and earnings of the Corporation and its affiliates throughout the world have been, and may in the future be, affected from time to time in varying degree by political developments and laws and regulations, such as forced divestiture of assets; restrictions on production, imports and exports; price controls; tax increases and retroactive tax claims; expropriation of property; cancellation of contract rights; and environmental regulations. Both the likelihood of such occurrences and their overall effect upon the Corporation vary greatly from country to country and are not predictable.

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17. Annuity Benefits and Other Postretirement Benefits

	Annuity Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	(millions of dollars)								
Components of net benefit cost									
Service cost	$ 308	$ 284	$ 224	$ 357	$ 326	$ 257	$ 62	$ 36	$ 30
Interest cost	611	624	577	812	728	621	295	234	220
Expected return on plan assets	(618)	(418)	(501)	(684)	(552)	(561)	(36)	(31)	(38)
Amortization of actuarial loss/(gain) and prior service cost	286	321	121	378	384	190	191	96	57
Net pension enhancement and curtailment/settlement expense	177	204	49	3	37	18	—	—	—
Net benefit cost	$ 764	$1,015	$ 470	$ 866	$ 923	$ 525	$ 512	$ 335	$ 269
Weighted-average assumptions used to determine net benefit cost for years ended December 31	*(percent)*								
Discount rate	6.00	6.75	7.25	5.2	5.2	5.6	6.00	6.75	7.25
Long-term rate of return on funded assets	9.00	9.00	9.50	7.7	7.7	8.0	9.00	9.00	9.50
Long-term rate of compensation increase	3.50	3.50	3.50	3.8	3.9	4.0	3.50	3.50	3.50

Costs for defined contribution plans were $245 million, $253 million and $191 million in 2004, 2003 and 2002, respectively.

The benefit obligations and plan assets associated with the Corporation's principal benefit plans are measured on December 31.

	Annuity Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2004	2003	2004	2003	2004	2003
	(millions of dollars)					
Change in benefit obligation [(1)]						
Benefit obligation at January 1	$10,280	$ 9,139	$16,313	$13,543	$4,960	$3,496
Service cost	308	284	357	326	62	36
Interest cost	611	624	812	728	295	234
Actuarial loss/(gain)	700	1,060	874	295	330	1,192
Benefits paid	(1,127)	(829)	(1,020)	(929)	(350)	(338)
Foreign exchange rate changes	—	—	1,182	2,184	29	53
Other	(2)	2	186	166	62	287
Projected benefit obligation at December 31	$10,770	$10,280	$18,704	$16,313	$5,388	$4,960
Accumulated benefit obligation at December 31	$ 9,193	$ 8,764	$17,003	$14,904	—	—
Weighted-average assumptions used to determine benefit obligations at December 31	*(percent)*					
Discount rate	5.75	6.00	4.9	5.2	5.75	6.00
Long-term rate of compensation increase	3.50	3.50	3.8	3.8	3.50	3.50

(1) *The term benefit obligation means "projected benefit obligation" as defined by Statement of Financial Accounting Standards No. 87 (FAS 87), "Employers' Accounting for Pensions," for annuity benefits and "accumulated postretirement benefit obligation" as defined by FAS 106, "Employers' Accounting for Postretirement Benefits Other than Pensions," for other postretirement benefits.*

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 6 percent for 2005 that declines to 2.5 percent by 2011. The 2003 actuarial loss for other postretirement benefits reflects a change in the health care cost trend rate assumption at year-end 2003. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $33 million and the postretirement benefit obligation by $373 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $27 million and the postretirement benefit obligation by $316 million.

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The Corporation offers a Medicare supplement plan to Medicare-eligible retirees that provides prescription drug benefits. On December 8, 2003, the President of the United States signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the “Act”). The Act provides a federal subsidy to employers sponsoring retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. The Corporation believes that its Medicare supplement plan is at least actuarially equivalent to Medicare Part D but that it is not a significant event for the plan. Accordingly, the Corporation recognized the effects of the Act at the December 31, 2004, measurement date.

	Annuity Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2004	2003	2004	2003	2004	2003
	(millions of dollars)					
Change in plan assets						
Fair value at January 1	$ 7,301	$4,616	$ 9,185	$6,735	$ 412	$ 345
Actual return on plan assets	967	1,327	1,086	1,114	50	86
Foreign exchange rate changes	—	—	691	1,202	—	—
Payments directly to participants	157	133	303	297	236	213
Company contribution	—	2,054	473	779	34	34
Benefits paid	(1,127)	(829)	(1,020)	(929)	(350)	(338)
Other	1	—	(45)	(13)	62	72
Fair value at December 31	$ 7,299	$7,301	$10,673	$9,185	$ 444	$ 412

The data on the preceding page conform with current accounting standards that specify use of a discount rate at which postretirement liabilities could be effectively settled. The discount rate for calculating year-end postretirement liabilities is based on the year-end rate of interest on a portfolio of high-quality bonds. The return on the annuity fund’s actual portfolio of assets has historically been higher than bonds as the majority of pension assets are invested in equities, as illustrated in the table below, which shows asset allocation. The U.S. long-term expected rate of return of 9.0 percent used in 2004 compares to an actual rate of return for the U.S. annuity fund over the past decade of 12.5 percent. The Corporation establishes the long-term expected rate of return for each plan by developing a forward-looking, long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation and the long-term return assumption for each asset class.

	Annuity Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2004	2003	2004	2003	2004	2003
	(percent)					
Funded benefit plan asset allocation						
Equity securities	75%	71%	69%	67%	76%	76%
Debt securities	25	25	29	31	24	24
Other	—	4	2	2	—	—
Total	100%	100%	100%	100%	100%	100%

The Corporation’s investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification to reduce the risk of the portfolio. The Corporation primarily invests in funds that follow an index-based strategy to achieve its objectives of diversifying risk while minimizing costs. The funds hold ExxonMobil stock only to the extent necessary to replicate the relevant equity index. Asset-liability studies, or simulations of the interaction of cash flows associated with both assets and liabilities, are periodically used to establish the preferred target asset allocation. The target asset allocation for equity securities of 75 percent for the U.S. benefit plans and 67 percent for non-U.S. plans reflects the long-term nature of the liability. The balance of the funds is largely targeted to debt securities.

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The funding levels of all qualified plans are in compliance with standards set by applicable law or regulation. Certain smaller U.S. plans and a number of non-U.S. plans are not funded because local tax conventions and regulatory practices do not encourage funding of these plans. All defined-benefit pension obligations, regardless of the funding status of the underlying plans, are fully supported by the financial strength of the Corporation or the respective sponsoring affiliate.

A summary comparing the total plan assets to the total projected benefit obligation is shown in the table below:

	Annuity Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2004	2003	2004	2003	2004	2003
			(millions of dollars)			
Assets in excess of/(less than) projected benefit obligation						
Balance at December 31 [(1)]	$(3,471)	$(2,979)	$(8,031)	$(7,128)	$(4,944)	$(4,548)
Unrecognized net transition liability/(asset)	—	—	2	48	—	—
Unrecognized net actuarial loss/(gain)	2,638	2,723	4,859	4,330	1,696	1,485
Unrecognized prior service cost	172	199	512	363	567	645
Net amount recognized	$ (661)	$ (57)	$(2,658)	$(2,387)	$(2,681)	$(2,418)
Amounts recognized in the consolidated balance sheet consist of:						
Prepaid benefit cost [(2)]	$ 71	$ 64	$ 713	$ 794	$ —	$ —
Accrued benefit cost [(3)]	(1,951)	(1,512)	(7,081)	(6,498)	(2,681)	(2,418)
Intangible assets	244	281	712	429	—	—
Equity of minority shareholders	—	—	117	146	—	—
Accumulated other nonowner changes in equity, minimum pension liability adjustment	975	1,110	2,881	2,742	—	—
Net amount recognized	$ (661)	$ (57)	$(2,658)	$(2,387)	$(2,681)	$(2,418)

(1) *Fair value of assets less projected benefit obligation shown in the preceding tables.*

(2) *Included in "Other assets, including intangibles, net" on the Consolidated Balance Sheet.*

(3) *Long-term portion in "Annuity Reserves" and short-term portion in "Accounts payable and accrued liabilities" on the Consolidated Balance Sheet.*

	Annuity Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
		(millions of dollars)	
Contributions expected in 2005	$ —	$ 1,300	$ 35
Benefit payments expected in:			
2005	649	938	359
2006	675	952	347
2007	732	981	353
2008	776	1,000	358
2009	829	1,018	366
2010 - 2014	4,846	5,643	1,906

A summary of the change in other nonowner changes in equity related to the minimum pension liability adjustment is shown in the table below:

	Annuity Benefits	
	Total (U.S. and Non-U.S.)	
	2004	2003
	(millions of dollars)	
Increase/(decrease) in accumulated other nonowner changes in equity, before tax	$ (4)	$ 895
Deferred income tax (charge)/credit (see note 19, page 77)	(49)	(381)
Increase/(decrease) in accumulated other nonowner changes in equity, after tax (see Consolidated Statement of Shareholders' Equity, page 52)	$ (53)	$ 514

A summary of pension plans with an accumulated benefit obligation in excess of plan assets is shown in the table below:

	Annuity Benefits			
	U.S.		Non-U.S.	
	2004	2003	2004	2003
	(millions of dollars)			
For funded pension plans with accumulated benefit obligations in excess of plan assets:				
Projected benefit obligation	$ 9,397	$ 8,999	$ 11,552	$ 9,886
Accumulated benefit obligation	8,038	7,643	10,681	9,172
Fair value of plan assets	7,127	7,141	8,128	6,719
Accumulated benefit obligation less fair value of plan assets	911	502	2,553	2,453
For unfunded plans covered by book reserves:				
Projected benefit obligation	1,260	1,168	4,827	4,342
Accumulated benefit obligation	1,041	1,010	4,305	3,872

18. Disclosures about Segments and Related Information

The Upstream, Downstream and Chemical functions best define the operating segments of the business that are reported separately. The factors used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment. The Upstream segment is organized and operates to explore for and produce crude oil and natural gas. The Downstream segment is organized and operates to manufacture and sell petroleum products, and the Chemical segment is organized and operates to manufacture and sell petrochemicals. These segments are broadly understood across the petroleum and petrochemical industries.

These functions have been defined as the operating segments of the Corporation because they are the segments (a) that engage in business activities from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the Corporation’s chief operating decision maker to make decisions about resources to be allocated to the segment and assess its performance; and (c) for which discrete financial information is available.

Earnings include special items and transfers are at estimated market prices. Consistent with a change in internal organization in 2002, earnings from the electric power business, previously reported in the Other segment, are now shown within non-U.S. Upstream. Earnings from the divested coal and minerals businesses are shown as discontinued operations and are included within the Other segment. In addition to discontinued operations, the Other segment includes corporate and financing activities and merger-related expenses. The interest revenue amount relates to interest earned on cash deposits and marketable securities. Interest expense includes nondebt-related interest expense of $529 million, $106 million and $207 million in 2004, 2003 and 2002, respectively. The increase in 2004 reflects the interest component of the Allapattah lawsuit provision. U.S. Downstream after-tax earnings in 2004 include a special charge of $550 million relating to the Allapattah lawsuit provision. Non-U.S. Upstream after-tax earnings in 2003 include $1,700 million from a gain on the transfer of shares in Ruhrgas AG, a German gas transmission company. All Other after-tax earnings in 2003 include $2,230 million relating to the positive settlement of a long-running U.S. tax dispute. All Other after-tax earnings in 2003 also include a $550 million positive impact for the required adoption of FAS 143 relating to accounting for asset retirement obligations. Non-U.S. Upstream after-tax earnings in 2002 include a special charge of $215 million reflecting the impact on deferred taxes from the 10 percent supplementary tax enacted in the United Kingdom in 2002.

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	Upstream		Downstream		Chemical			
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	All Other	Corporate Total
				(millions of dollars)				
As of December 31, 2004								
Earnings after income tax	$ 4,948	$11,727	$ 2,186	$ 3,520	$ 1,020	$ 2,408	$ (479)	$ 25,330
Earnings of equity companies included above	904	2,709	138	466	31	914	(201)	4,961
Sales and other operating revenue	5,990	17,043	71,645	168,768	10,729	17,052	25	291,252
Intersegment revenue	6,547	21,800	8,047	26,577	4,937	4,278	306	—
Depreciation and depletion expense	1,453	4,758	618	1,646	408	400	484	9,767
Interest revenue	—	—	—	—	—	—	361	361
Interest expense	—	—	—	—	—	—	638	638
Income taxes	2,733	10,168	1,371	1,073	450	731	(615)	15,911
Additions to property, plant and equipment	1,465	7,358	668	1,472	247	201	575	11,986
Investments in equity companies	1,347	6,595	401	1,047	276	2,079	(3)	11,742
Total assets	19,330	62,204	14,685	49,688	8,102	13,052	28,195	195,256
As of December 31, 2003								
Earnings after income tax	$ 3,905	$10,597	$ 1,348	$ 2,168	$ 381	$ 1,051	$ 2,060	$ 21,510
Earnings of equity companies included above	525	3,335	36	240	16	409	(188)	4,373
Sales and other operating revenue	5,942	15,388	56,373	139,138	7,792	12,398	23	237,054
Intersegment revenue	5,479	15,782	5,627	18,752	3,403	3,237	310	—
Depreciation and depletion expense	1,571	4,072	601	1,548	410	368	477	9,047
Interest revenue	—	—	—	—	—	—	229	229
Interest expense	—	—	—	—	—	—	207	207
Income taxes	2,175	7,237	757	795	67	325	(350)	11,006
Additions to property, plant and equipment	1,701	7,529	1,159	1,416	313	186	555	12,859
Investments in equity companies	1,266	5,176	316	909	266	1,612	—	9,545
Total assets	19,196	56,237	14,436	46,060	7,722	11,786	18,841	174,278
As of December 31, 2002								
Earnings after income tax	$ 2,524	$ 7,074	$ 693	$ 607	$ 384	$ 446	$ (268)	$ 11,460
Earnings of equity companies included above	391	1,761	(40)	27	24	175	(272)	2,066
Sales and other operating revenue	3,896	12,588	48,865	119,167	6,891	9,517	25	200,949
Intersegment revenue	5,020	12,144	4,540	15,157	2,666	2,486	269	—
Depreciation and depletion expense	1,597	3,551	583	1,399	414	348	418	8,310
Interest revenue	—	—	—	—	—	—	297	297
Interest expense	—	—	—	—	—	—	398	398
Income taxes	1,321	5,162	359	44	165	189	(741)	6,499
Additions to property, plant and equipment	1,902	6,122	884	1,357	448	181	543	11,437
Investments in equity companies	1,360	2,867	246	795	265	1,399	—	6,932
Total assets	19,385	47,040	13,562	41,530	7,543	10,581	13,003	152,644

Geographic Sales and other operating revenue	2004	2003	2002
		(millions of dollars)	
United States	$ 88,382	$ 70,128	$ 59,675
Non-U.S.	202,870	166,926	141,274
Total	$ 291,252	$ 237,054	$ 200,949
Significant non-U.S. revenue sources include:			
Japan	$ 25,485	$ 22,360	$ 19,300
United Kingdom	22,549	19,946	17,701
Canada	21,689	17,897	14,087
Germany	17,649	15,764	14,101
Italy	15,096	13,074	10,727
France	12,231	9,725	8,416

Long-lived assets	2004	2003	2002
		(millions of dollars)	
United States	$ 33,569	$ 34,585	$ 34,138
Non-U.S.	75,070	70,380	60,802
Total	$ 108,639	$ 104,965	$ 94,940
Significant non-U.S. long-lived assets include:			
Canada	$ 11,806	$ 10,849	$ 8,469
United Kingdom	9,545	9,615	9,030
Norway	7,561	7,047	6,449

Nigeria	4,923	3,833	2,633
Japan	4,784	4,931	4,637
Angola	3,544	2,666	1,678
Singapore	3,089	3,252	3,407

19. Income, Excise and Other Taxes

	2004			2003			2002		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
	(millions of dollars)								
Income taxes									
Federal or non-U.S.									
Current	$ 4,410	$ 12,030	$ 16,440	$ 1,522	$ 7,426	$ 8,948	$ 351	$ 5,618	$ 5,969
Deferred – net	(1,113)	122	(991)	996	645	1,641	635	(288)	347
U.S. tax on non-U.S. operations	56	—	56	71	—	71	62	—	62
	3,353	12,152	15,505	2,589	8,071	10,660	1,048	5,330	6,378
State	406	—	406	346	—	346	121	—	121
Total income taxes	3,759	12,152	15,911	2,935	8,071	11,006	1,169	5,330	6,499
Excise taxes	6,833	20,430	27,263	6,323	17,532	23,855	7,174	14,866	22,040
All other taxes and duties									
Other taxes and duties	26	40,928	40,954	22	37,623	37,645	35	33,537	33,572
Included in production and manufacturing expenses	982	951	1,933	976	812	1,788	914	674	1,588
Included in SG&A expenses	215	503	718	211	463	674	171	415	586
Total other taxes and duties	1,223	42,382	43,605	1,209	38,898	40,107	1,120	34,626	35,746
Total	$ 11,815	$ 74,964	$ 86,779	$ 10,467	$ 64,501	$ 74,968	$ 9,463	$ 54,822	$ 64,285

All other taxes and duties include taxes reported in production and manufacturing and selling, general and administrative (SG&A) expenses. The above provisions for deferred income taxes include net (charges)/credits for the effect of changes in tax laws and rates of $318 million in 2004, $124 million in 2003 and $(194) million in 2002. Income taxes (charged)/credited directly to shareholders' equity were:

	2004	2003	2002
	(millions of dollars)		
Cumulative foreign exchange translation adjustment	$(180)	$(233)	$ (331)
Minimum pension liability adjustment	(49)	(381)	1,373
Unrealized gains and losses on stock investments	53	(331)	(8)
Other components of shareholders' equity	183	107	86

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2004, 2003 and 2002, is as follows:

	2004	2003	2002
	(millions of dollars)		
Earnings before federal and non-U.S. income taxes			
United States	$11,067	$ 9,438	$ 4,340
Non-U.S.	29,768	22,182	13,049
Total	$40,835	$31,620	$17,389
Theoretical tax	$14,292	$11,067	$ 6,086
Effect of equity method accounting	(1,736)	(1,531)	(723)
Non-U.S. taxes in excess of theoretical U.S. tax	3,093	1,635	1,355
U.S. tax on non-U.S. operations	56	71	62
U.S. tax settlement	—	(541)	—
Other U.S.	(200)	(41)	(402)
Federal and non-U.S. income tax expense	$15,505	$10,660	$ 6,378
Total effective tax rate	40.3%	36.4%	39.8%

The effective income tax rate includes state income taxes and the Corporation's share of income taxes of equity companies. Equity company taxes totaled $1,180 million in 2004, $983 million in 2003 and $778 million in 2002, primarily outside the U.S.

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

Deferred tax liabilities/(assets) are comprised of the following at December 31:

Tax effects of temporary differences for:	2004	2003
	(millions of dollars)	
Depreciation	$16,732	$16,284
Intangible development costs	4,733	3,821
Capitalized interest	2,279	2,109
Other liabilities	3,295	4,521
Total deferred tax liabilities	$27,039	$26,735

Pension and other postretirement benefits	$ (2,613)	$ (2,365)
Tax loss carryforwards	(2,399)	(2,500)
Other assets	(3,761)	(3,453)
Total deferred tax assets	$ (8,773)	$ (8,318)
Asset valuation allowances	686	854
Net deferred tax liabilities	$18,952	$19,271

Deferred income tax (assets) and liabilities are included in the balance sheet as shown below. Deferred income tax (assets) and liabilities are classified as current or long term consistent with the classification of the related temporary difference — separately by tax jurisdiction.

Balance sheet classification	**2004**	**2003**
	(millions of dollars)	
Prepaid taxes and expenses	$ (1,221)	$ (919)
Other assets, including intangibles, net	(1,406)	(1,647)
Accounts payable and accrued liabilities	487	1,719
Deferred income tax liabilities	21,092	20,118
Net deferred tax liabilities	$18,952	$19,271

The Corporation had $25 billion of indefinitely reinvested, undistributed earnings from subsidiary companies outside the U.S. Unrecognized deferred taxes on remittance of these funds are not expected to be material.

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

The results of operations for producing activities shown below are presented in accordance with Statement of Financial Accounting Standards No. 69. As such, it does not include earnings from other activities that ExxonMobil includes in the Upstream function such as oil and gas transportation operations, tar sands operations, LNG liquefaction and transportation operations, coal and power operations, technical services agreements, other nonoperating activities and adjustments for minority interests. These excluded amounts for both consolidated and equity companies totaled $1,340 million in 2004, $2,300 million in 2003 and $638 million in 2002.

Results of Operations	United States	Canada	Europe	Asia Pacific	Africa	Middle East	Other [1]	Total
				(millions of dollars)				
2004 – Revenue								
Sales to third parties	$ 4,203	$2,460	$ 6,714	$ 2,200	$ 29	$ 91	$ 554	$16,251
Transfers	5,555	2,680	5,347	2,615	7,272	155	179	23,803
	$ 9,758	$5,140	$12,061	$ 4,815	$7,301	$ 246	$ 733	$40,054
Production costs excluding taxes	1,442	1,085	1,932	622	719	41	164	6,005
Exploration expenses	193	92	112	108	321	32	228	1,086
Depreciation and depletion	1,335	969	2,082	667	839	35	95	6,022
Taxes other than income	550	49	582	633	722	1	3	2,540
Related income tax	2,546	1,015	4,417	1,022	2,789	78	102	11,969
Results of producing activities for consolidated subsidiaries	$ 3,692	$1,930	$ 2,936	$ 1,763	$1,911	$ 59	$ 141	$12,432
Proportional interest in results of producing activities of equity companies	$ 810	$ —	$ 993	$ —	$ —	$ 635	$ 465	$ 2,903
2003 – Revenue								
Sales to third parties	$ 4,257	$2,221	$ 5,267	$ 2,287	$ 56	$ 81	$ 378	$14,547
Transfers	4,619	2,090	4,397	2,066	4,443	145	161	17,921
	$ 8,876	$4,311	$ 9,664	$ 4,353	$4,499	$ 226	$ 539	$32,468
Production costs excluding taxes	1,435	1,054	1,688	558	564	48	146	5,493
Exploration expenses	257	92	144	146	217	33	119	1,008
Depreciation and depletion	1,456	782	1,833	727	459	43	95	5,395
Taxes other than income	540	39	658	447	528	1	3	2,216
Related income tax	2,017	738	2,902	1,046	1,496	50	44	8,293
Results of producing activities for consolidated subsidiaries	$ 3,171	$1,606	$ 2,439	$ 1,429	$1,235	$ 51	$ 132	$10,063
Proportional interest in results of producing activities of equity companies	$ 584	$ —	$ 836	$ —	$ —	$ 424	$ 295	$ 2,139
2002 – Revenue								
Sales to third parties	$ 2,499	$1,441	$ 4,856	$ 1,994	$ 18	$ 88	$ 255	$11,151
Transfers	4,176	1,617	3,334	2,022	3,046	133	140	14,468
	$ 6,675	$3,058	$ 8,190	$ 4,016	$3,064	$ 221	$ 395	$25,619
Production costs excluding taxes	1,405	766	1,493	592	455	49	143	4,903
Exploration expenses	222	66	109	88	177	21	236	919
Depreciation and depletion	1,512	681	1,737	651	354	40	110	5,085
Taxes other than income	459	31	360	403	345	1	3	1,602
Related income tax	1,153	486	2,399	939	972	80	(202)	5,827
Results of producing activities for consolidated subsidiaries	$ 1,924	$1,028	$ 2,092	$ 1,343	$ 761	$ 30	$ 105	$ 7,283
Proportional interest in results of producing activities of equity companies	$ 428	$ —	$ 680	$ (13)	$ —	$ 341	$ 241	$ 1,677

[1] *The Caspian region and South America.*

Average sales prices have been calculated by using sales quantities from the Corporation's own production as the divisor. Average production costs have been computed by using net production quantities for the divisor. The volumes of crude oil and natural gas liquids (NGL) production used for this computation are shown in the reserves table on page 83 of this report. The volumes for natural gas used for this calculation are the production volumes of natural gas available for sale and thus are different than those shown in the reserves table on page 84 of this report due to volumes consumed or flared. The volumes of natural gas were converted to oil-equivalent barrels based on a conversion factor of six thousand cubic feet per barrel.

Average sales prices and production costs per unit of production – consolidated subsidiaries	**United States**	**Canada**	**Europe**	**Asia Pacific**	**Africa**	**Middle East**	**Other [1]**	**Total**
				(millions of dollars)				
During 2004								
Average sales prices								
Crude oil and NGL, per barrel	$34.84	$30.26	$35.71	$39.09	$35.04	$38.49	$29.14	$34.76
Natural gas, per thousand cubic feet	5.53	5.23	4.20	3.41	—	—	1.13	4.48
Average production costs, per barrel [2]	5.05	6.47	4.95	3.74	3.44	6.22	5.20	4.78
During 2003								
Average sales prices								
Crude oil and NGL, per barrel	$25.74	$23.84	$27.15	$29.03	$28.29	$28.80	$22.55	$26.66
Natural gas, per thousand cubic feet	5.06	4.61	3.76	2.84	—	—	1.04	3.98
Average production costs, per barrel [2]	4.48	6.17	4.34	2.84	3.49	5.96	4.97	4.31
During 2002								
Average sales prices								
Crude oil and NGL, per barrel	$20.80	$20.73	$22.95	$24.26	$24.19	$24.62	$17.31	$22.30
Natural gas, per thousand cubic feet	2.67	2.34	3.08	2.26	—	—	0.48	2.65
Average production costs, per barrel [2]	3.97	4.53	3.82	2.72	3.57	5.31	4.94	3.78

(1) *The Caspian region and South America.*

(2) *Production costs exclude depreciation and depletion and all taxes. Natural gas included by conversion to crude oil-equivalent.*

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

Oil and Gas Exploration and Production Costs (unaudited)

The amounts shown for net capitalized costs of consolidated subsidiaries are $4,769 million less at year-end 2004 and $3,961 million less at year-end 2003 than the amounts reported as investments in property, plant and equipment for the Upstream in note 9, page 59. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to the tar sands and LNG operations, all as required in Statement of Financial Accounting Standards No. 19. Part of the increase in net capitalized costs at year-end 2003 reflected the adoption of Statement of Financial Accounting Standards No. 143.

Capitalized Costs	United States	Canada	Europe	Asia Pacific	Africa	Middle East	Other [(1)]	Total
				(millions of dollars)				
As of December 31, 2004								
Property (acreage) costs – Proved	$ 3,739	$ 3,414	$ 235	$ 339	$ 253	$ 659	$ 523	$ 9,162
– Unproved	623	244	35	863	552	—	326	2,643
Total property costs	$ 4,362	$ 3,658	$ 270	$ 1,202	$ 805	$ 659	$ 849	$ 11,805
Producing assets	34,875	11,318	43,899	14,175	8,537	862	1,220	114,886
Support facilities	617	119	530	1,113	383	10	95	2,867
Incomplete construction	1,637	419	1,136	1,495	4,782	239	1,682	11,390
Total capitalized costs	$ 41,491	$15,514	$45,835	$ 17,985	$14,507	$ 1,770	$3,846	$140,948
Accumulated depreciation and depletion	26,508	8,905	30,943	11,489	3,801	1,474	584	83,704
Net capitalized costs for consolidated subsidiaries	$ 14,983	$ 6,609	$14,892	$ 6,496	$10,706	$ 296	$3,262	$ 57,244
Proportional interest of net capitalized costs of equity companies	$ 1,234	$ —	$ 1,277	$ —	$ —	$ 767	$2,427	$ 5,705
As of December 31, 2003								
Property (acreage) costs – Proved	$ 4,188	$ 3,174	$ 219	$ 918	$ 116	$ 659	$ 359	$ 9,633
– Unproved	663	251	46	1,025	545	—	475	3,005
Total property costs	$ 4,851	$ 3,425	$ 265	$ 1,943	$ 661	$ 659	$ 834	$ 12,638
Producing assets	35,737	9,925	39,371	14,478	6,158	850	1,207	107,726
Support facilities	614	113	476	1,083	290	11	60	2,647
Incomplete construction	1,201	381	1,174	1,133	4,477	63	1,010	9,439
Total capitalized costs	$ 42,403	$13,844	$41,286	$ 18,637	$11,586	$ 1,583	$3,111	$132,450
Accumulated depreciation and depletion	26,903	7,401	26,719	11,749	2,980	1,437	495	77,684
Net capitalized costs for consolidated subsidiaries	$ 15,500	$ 6,443	$14,567	$ 6,888	$ 8,606	$ 146	$2,616	$ 54,766
Proportional interest of net capitalized costs of equity companies	$ 1,211	$ —	$ 1,263	$ —	$ —	$ 592	$2,043	$ 5,109

(1) *The Caspian region and South America.*

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Oil and Gas Exploration and Production Costs (unaudited) *(continued)*

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2004 were $9,017 million, down $819 million from 2003, due primarily to lower development costs. 2003 costs were $9,836 million, up $1,421 million from 2002, due primarily to higher development costs.

Costs incurred in property acquisitions, exploration and development activities	United States	Canada	Europe	Asia Pacific	Africa	Middle East	Other [(1)]	Total
				(millions of dollars)				
During 2004								
Property acquisition costs – Proved	$ —	$ —	$ —	$ —	$ 68	$ —	$ 25	$ 93
– Unproved	14	1	—	2	24	—	—	41
Exploration costs	232	68	123	113	382	33	239	1,190
Development costs	1,427	694	1,232	660	2,788	188	704	7,693
Total costs incurred for consolidated subsidiaries	$ 1,673	$ 763	$1,355	$ 775	$3,262	$ 221	$ 968	$9,017
Proportional interest of costs incurred of equity companies	$ 155	$ —	$ 169	$ —	$ —	$ 205	$ 451	$ 980
During 2003								
Property acquisition costs – Proved	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
– Unproved	17	7	4	—	17	—	—	45
Exploration costs	252	102	153	138	264	33	210	1,152
Development costs	1,636	644	1,755	929	3,117	69	489	8,639
Total costs incurred for consolidated subsidiaries	$ 1,905	$ 753	$1,912	$ 1,067	$3,398	$ 102	$ 699	$9,836
Proportional interest of costs incurred of equity companies	$ 145	$ —	$ 231	$ —	$ —	$ 146	$ 289	$ 811
During 2002								
Property acquisition costs – Proved	$ 18	$ 8	$ —	$ —	$ —	$ —	$ —	$ 26
– Unproved	13	12	—	—	10	—	125	160
Exploration costs	276	109	127	82	301	18	198	1,111
Development costs	1,676	653	1,785	936	1,708	44	316	7,118
Total costs incurred for consolidated subsidiaries	$ 1,983	$ 782	$1,912	$ 1,018	$2,019	$ 62	$ 639	$8,415
Proportional interest of costs incurred of equity companies	$ 173	$ —	$ 223	$ 13	$ —	$ 100	$ 231	$ 740

(1) *The Caspian region and South America.*

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

Oil and Gas Reserves (unaudited)

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2002, 2003 and 2004.

The definitions used are in accordance with the Securities and Exchange Commission's Rule 4-10 (a) of Regulation S-X, paragraphs (2) through (2)iii, (3) and (4).

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements but not on escalations based upon future conditions. In some cases, substantial new investments in additional wells and related facilities will be required to recover these proved reserves. In certain deepwater fields, proved reserves are recorded in a limited number of cases before flow tests are conducted because of the safety and cost implications of conducting the tests. In those situations, other industry-accepted analyses are used. Historically, proved reserves recorded using these methods have been immaterial when compared to the Corporation's total proved reserves and have also been validated by subsequent flow tests or actual production levels.

Based on regulatory guidance, the Corporation has reported 2004 reserves on the basis of December 31, 2004, prices and costs ("year-end prices").

The use of year-end prices for reserves estimation introduces short-term price volatility into the process since annual adjustments will be required based on prices occurring on a single day. The Corporation believes that this approach is inconsistent with the long-term nature of the upstream business where production from individual projects often spans multiple decades. The use of prices from a single date is not relevant to the investment decisions made by the Corporation and annual variations in reserves based on such year-end prices are not of consequence to how the business is actually managed.

The impact of year-end prices on reserve estimation is most graphically shown at the Cold Lake field (heavy oil-bitumen steam project) in Canada where proved reserves were reduced by approximately 0.5 billion oil-equivalent barrels as a result of employing December 31 prices, which were unusually low for bitumen. However, bitumen prices in western Canada increased substantially after December 31 and resulted in the rebooking of approximately 0.5 billion oil-equivalent barrels at the Cold Lake field in 2005.

Performance-related revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of (1) already available geologic, reservoir or production data or (2) new geologic, reservoir or production data. This category can also include changes associated with the performance of improved recovery projects and significant changes in either development strategy or production equipment/facility capacity.

Proved reserves include 100 percent of each majority-owned affiliate's participation in proved reserves and ExxonMobil's ownership percentage of the proved reserves of equity companies, but exclude royalties and quantities due others. Gas reserves exclude the gaseous equivalent of liquids expected to be removed from the gas on leases, at field facilities and at gas processing plants. These liquids are included in net proved reserves of crude oil and natural gas liquids.

In the reserves tables on pages 83 to 85, consolidated reserves and equity reserves are reported separately. However, the Corporation does not view equity reserves any differently than those from consolidated companies.

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The percentage of conventional liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2004 that were associated with production sharing contract arrangements was 17 percent of liquids, 9 percent of natural gas and 13 percent on an oil-equivalent basis (gas converted to oil-equivalent at 6 billion cubic feet = 1 million barrels).

Net proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipment and operating methods. Undeveloped reserves are those volumes that are expected to be recovered as a result of future investments to drill new wells, to recomplete existing wells and/or to install facilities to collect and deliver the production from existing and future wells.

Crude oil and natural gas liquids and natural gas production quantities shown are the net volumes withdrawn from ExxonMobil's oil and gas reserves. The natural gas quantities differ from the quantities of gas delivered for sale by the producing function as reported on page 89 due to volumes consumed or flared and inventory changes.

(unaudited)

Crude Oil and Natural Gas Liquids	United States	Canada [1]	Europe	Asia Pacific	Africa	Middle East [2]	Other [3]	Total
				(millions of barrels)				
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2002	3,028	1,277	1,476	622	2,461	30	658	9,552
Revisions	31	74	59	40	73	3	23	303
Purchases	—	—	—	—	—	—	—	—
Sales	(13)	—	—	—	—	—	—	(13)
Improved recovery	3	—	—	—	75	—	—	78
Extensions and discoveries	60	40	11	124	145	—	100	480
Production	(200)	(106)	(213)	(95)	(128)	(9)	(24)	(775)
December 31, 2002	2,909	1,285	1,333	691	2,626	24	757	9,625
Revisions	31	14	50	67	176	1	2	341
Purchases	1	—	—	—	—	—	—	1
Sales	(14)	—	(2)	—	—	—	—	(16)
Improved recovery	16	3	1	—	66	—	—	86
Extensions and discoveries	27	6	10	12	36	49	491	631
Production	(178)	(114)	(208)	(86)	(162)	(8)	(23)	(779)
December 31, 2003	2,792	1,194	1,184	684	2,742	66	1,227	9,889
Performance-related revisions	(46)	4	35	17	(39)	(4)	77	44
Purchases	—	—	—	—	10	—	—	10
Sales	(113)	(3)	—	(16)	—	—	—	(132)
Improved recovery	5	—	—	—	—	—	—	5
Extensions and discoveries	15	4	3	2	150	—	—	174
Production	(161)	(108)	(210)	(74)	(209)	(7)	(26)	(795)
Total before year-end price/cost revisions	2,492	1,091	1,012	613	2,654	55	1,278	9,195
Year-end price/cost revisions	101	(464)	2	(12)	(210)	(6)	(211)	(800)
December 31, 2004	2,593	627	1,014	601	2,444	49	1,067	8,395
Proportional interest in proved reserves of equity companies								
End of year 2002	443	—	26	—	—	779	950	2,198
End of year 2003	426	—	20	—	—	767	973	2,186
End of year 2004 [4]	402	—	17	—	—	1,169	911	2,499
Proved developed reserves, included above, as of December 31, 2002								
Consolidated subsidiaries	2,461	685	797	487	1,057	23	185	5,695
Equity companies	374	—	20	—	—	652	459	1,505
Proved developed reserves, included above, as of December 31, 2003								
Consolidated subsidiaries	2,348	750	805	473	1,107	16	165	5,664
Equity companies	363	—	16	—	—	616	513	1,508
Proved developed reserves, included above, as of December 31, 2004								
Consolidated subsidiaries	2,204	561	763	394	1,117	9	163	5,211
Equity companies	347	—	15	—	—	642	600	1,604

(1) *Includes total proved reserves attributable to Imperial Oil Limited of 947 million barrels in 2002, 889 million barrels in 2003 and 347 million barrels in 2004, as well as proved developed reserves of 447 million barrels in 2002, 519 million barrels in 2003 and 343 million barrels in 2004, in which there is a 30.4 percent minority interest.*

(2) *2003 reserves were adjusted to reflect the movement of equity company volumes to consolidated company reserves.*

(3) *The Caspian region and South America.*

(4) *Year-end 2004 equity company total reserves of 2,499 million barrels included a negative revision of 62 million barrels due to the use of year-end prices and costs.*

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

Oil and Gas Reserves *(continued)*

Natural Gas	United States	Canada (1)	Europe	Asia Pacific	Africa	Middle East (2)	Other (3)	Total
				(billions of cubic feet)				
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2002	12,732	3,183	10,931	8,301	379	38	690	36,254
Revisions	206	30	600	258	17	—	42	1,153
Purchases	—	2	—		—	—	—	2
Sales	(43)	—	—	—	—	—	—	(43)
Improved recovery	1	3	—	—	—	—	—	4
Extensions and discoveries	209	83	115	212	52	—	9	680
Production	(1,043)	(419)	(1,138)	(813)	(12)	(8)	(36)	(3,469)
December 31, 2002	12,062	2,882	10,508	7,958	436	30	705	34,581
Revisions	124	(199)	411	23	157	(4)	(2)	510
Purchases	10	—	—	—	—			10
Sales	(90)	—	(3)	—	—	—	—	(93)
Improved recovery	9	1	—	—	—	—	—	10
Extensions and discoveries	156	45	333	22	1	849	239	1,645
Production	(999)	(388)	(1,103)	(718)	(11)	(9)	(40)	(3,268)
December 31, 2003	11,272	2,341	10,146	7,285	583	866	902	33,395
Performance-related revisions	31	19	(65)	(375)	165	(75)	211	(89)
Purchases	—	—	—	—	9	—	—	9
Sales	(142)	(18)	(16)	(301)	—	—	—	(477)
Improved recovery	2	—	31	—	—	—	—	33
Extensions and discoveries	121	36	39	44	39	—	—	279
Production	(846)	(399)	(1,092)	(624)	(25)	(9)	(40)	(3,035)
Total before year-end price/cost revisions	10,438	1,979	9,043	6,029	771	782	1,073	30,115
Year-end price/cost revisions	1,891	(96)	142	(110)	—	(98)	(1)	1,728
December 31, 2004	12,329	1,883	9,185	5,919	771	684	1,072	31,843
Proportional interest in proved reserves of equity companies								
End of year 2002	177	—	13,828	—	—	5,692	1,440	21,137
End of year 2003	152	—	13,703	—	—	6,055	1,464	21,374
End of year 2004 (4)	140	—	13,557	—	—	13,455	1,367	28,519

(1) *Includes total proved reserves attributable to Imperial Oil Limited of 1,224 billion cubic feet in 2002, 1,023 billion cubic feet in 2003 and 791 billion cubic feet in 2004, in which there is a 30.4 percent minority interest.*

(2) *2003 reserves were adjusted to reflect the movement of equity company volumes to consolidated company reserves.*

(3) *The Caspian region and South America.*

(4) *Year-end 2004 equity company total reserves of 28,519 billion cubic feet included a positive revision of 694 billion cubic feet due to the use of year-end prices and costs.*

(unaudited)

Natural Gas *(continued)*	United States	Canada [(1)]	Europe	Asia Pacific	Africa	Middle East	Other [(2)]	Total
				(billions of cubic feet)				
Proved developed reserves, included above, as of December 31, 2002								
Consolidated subsidiaries	9,991	2,294	7,326	5,887	112	30	372	26,012
Equity companies	137	—	5,602	—	—	2,358	634	8,731
Proved developed reserves, included above, as of December 31, 2003								
Consolidated subsidiaries	9,513	1,962	7,196	5,764	155	21	331	24,942
Equity companies	124	—	7,770	—	—	2,689	709	11,292
Proved developed reserves, included above, as of December 31, 2004								
Consolidated subsidiaries	9,134	1,647	7,076	4,428	279	12	283	22,859
Equity companies	120	—	9,805	—	—	4,578	837	15,340

(1) *Includes proved developed reserves attributable to Imperial Oil Limited of 959 billion cubic feet in 2002, 859 billion cubic feet in 2003 and 704 billion cubic feet in 2004, in which there is a 30.4 percent minority interest.*

(2) *The Caspian region and South America.*

INFORMATION ON CANADIAN TAR SANDS PROVEN RESERVES NOT INCLUDED ABOVE

In addition to conventional liquids and natural gas proved reserves, ExxonMobil has significant interests in proven tar sands reserves in Canada associated with the Syncrude project. For internal management purposes, ExxonMobil views these reserves and their development as an integral part of total upstream operations. However, for financial reporting purposes, these reserves are required to be reported separately from the oil and gas reserves.

The tar sands reserves are not considered in the standardized measure of discounted future cash flows for conventional oil and gas reserves, which is found on page 86.

Tar Sands Reserves	Canada
	(millions of barrels)
At December 31, 2002	800
At December 31, 2003	781
At December 31, 2004	757

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (unaudited)

Standardized Measure of Discounted Future Cash Flows

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows is computed by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment and rehabilitation obligations. The Corporation believes the standardized measure does not provide a reliable estimate of the Corporation's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including year-end prices, which represent a single point in time and therefore may cause significant variability in cash flows from year to year as prices change.

Standardized Measure of Discounted Future Cash Flows	United States	Canada (1)	Europe	Asia Pacific	Africa	Middle East (2)	Other (3)	Total
				(millions of dollars)				
Consolidated subsidiaries								
As of December 31, 2002								
Future cash inflows from sales of oil and gas	$ 118,905	$ 38,528	$ 68,111	$ 36,917	$ 76,407	$ 695	$ 17,626	$ 357,189
Future production costs	26,601	7,910	14,781	9,889	13,673	113	3,325	76,292
Future development costs	5,545	3,157	5,983	3,433	10,454	—	1,789	30,361
Future income tax expenses	34,289	10,261	23,580	8,254	28,190	315	3,606	108,495
Future net cash flows	$ 52,470	$ 17,200	$ 23,767	$ 15,341	$ 24,090	$ 267	$ 8,906	$ 142,041
Effect of discounting net cash flows at 10%	28,930	6,792	7,788	5,857	11,658	42	5,592	66,659
Discounted future net cash flows	$ 23,540	$ 10,408	$ 15,979	$ 9,484	$ 12,432	$ 225	$ 3,314	$ 75,382
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 3,930	$ —	$ 7,140	$ —	$ —	$ 6,218	$ 3,889	$ 21,177
Consolidated subsidiaries								
As of December 31, 2003								
Future cash inflows from sales of oil and gas	$ 127,459	$ 35,637	$ 71,937	$ 37,006	$ 76,969	$ 1,784	$ 27,735	$ 378,527
Future production costs	26,777	11,451	16,090	10,860	15,017	145	4,324	84,664
Future development costs	4,537	3,659	6,966	3,740	7,576	76	3,787	30,341
Future income tax expenses	38,690	7,835	25,080	8,819	29,808	714	5,418	116,364
Future net cash flows	$ 57,455	$ 12,692	$ 23,801	$ 13,587	$ 24,568	$ 849	$ 14,206	$ 147,158
Effect of discounting net cash flows at 10%	31,107	4,688	7,970	5,290	10,868	436	9,862	70,221
Discounted future net cash flows	$ 26,348	$ 8,004	$ 15,831	$ 8,297	$ 13,700	$ 413	$ 4,344	$ 76,937
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 4,007	$ —	$ 9,826	$ —	$ —	$ 4,627	$ 3,849	$ 22,309
Consolidated subsidiaries								
As of December 31, 2004								
Future cash inflows from sales of oil and gas	$ 141,261	$ 25,008	$ 79,698	$ 34,921	$ 87,687	$ 1,850	$ 31,935	$ 402,360
Future production costs	30,096	5,686	17,847	10,691	17,929	183	4,125	86,557
Future development costs	6,181	2,743	7,670	3,682	7,822	59	3,923	32,080
Future income tax expenses	42,928	5,662	28,883	7,066	33,945	840	6,707	126,031
Future net cash flows	$ 62,056	$ 10,917	$ 25,298	$ 13,482	$ 27,991	$ 768	$ 17,180	$ 157,692
Effect of discounting net cash flows at 10%	36,078	3,598	8,485	5,342	11,287	362	11,456	76,608
Discounted future net cash flows	$ 25,978	$ 7,319	$ 16,813	$ 8,140	$ 16,704	$ 406	$ 5,724	$ 81,084
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 4,079	$ —	$ 9,612	$ —	$ —	$ 11,137	$ 4,784	$ 29,612

(1) *Includes discounted future net cash flows attributable to Imperial Oil Limited of $5,210 million in 2002, $3,667 million in 2003 and $2,773 million in 2004, in which there is a 30.4 percent minority interest.*

(2) *2003 cash flows were adjusted to reflect the movement of equity company cash flows to consolidated company cash flows.*

(3) *The Caspian region and South America.*

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(unaudited)

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

Consolidated Subsidiaries	2004	2003 [(1)]	2002
		(millions of dollars)	
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	$ 588	$ 4,431	$ 5,481
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(31,726)	(25,012)	(19,242)
Development costs incurred during the year	7,660	8,350	6,994
Net change in prices, lifting and development costs	21,267	4,014	57,506
Revisions of previous reserves estimates	(766)	2,234	4,665
Accretion of discount	10,645	10,513	5,837
Net change in income taxes	(3,521)	(2,975)	(26,973)
Total change in the standardized measure during the year	$ 4,147	$ 1,555	$ 34,268

[(1)] *2003 change in standardized measure was adjusted to reflect the movement of equity company cash flows to consolidated company cash flows.*

QUARTERLY INFORMATION

	2004					2003				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
					(thousands of barrels daily)					
Volumes										
Production of crude oil and natural gas liquids	2,635	2,581	2,505	2,565	2,571	2,504	2,477	2,485	2,595	2,516
Refinery throughput	5,596	5,589	5,809	5,852	5,713	5,390	5,491	5,555	5,603	5,510
Petroleum product sales	8,126	8,023	8,242	8,446	8,210	7,859	7,795	7,931	8,237	7,957
					(millions of cubic feet daily)					
Natural gas production available for sale	11,488	9,061	8,488	10,430	9,864	12,046	9,283	8,323	10,858	10,119
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production [(1)]	4,550	4,091	3,920	4,303	4,215	4,512	4,024	3,872	4,405	4,203
					(thousands of metric tons)					
Chemical prime product sales	6,792	6,930	7,117	6,949	27,788	6,880	6,335	6,660	6,692	26,567
Summarized financial data										
					(millions of dollars)					
Sales and other operating revenue	$ 66,060	69,220	74,854	81,118	291,252	$ 60,188	56,167	58,760	61,939	237,054
Gross profit [(2)]	$ 27,619	28,202	29,655	33,560	119,036	$ 24,588	24,451	24,007	26,043	99,089
Income from continuing operations	$ 5,440	5,790	5,680	8,420	25,330	$ 6,490	4,170	3,650	6,650	20,960
Accounting change, net of income tax	$ —	—	—	—	—	$ 550	—	—	—	550
Net income	$ 5,440	5,790	5,680	8,420	25,330	$ 7,040	4,170	3,650	6,650	21,510
Per share data										
					(dollars per share)					
Income from continuing operations	$ 0.83	0.89	0.88	1.31	3.91	$ 0.97	0.63	0.55	1.01	3.16
Accounting change, net of income tax	$ —	—	—	—	—	$ 0.08	—	—	—	0.08
Net income per common share	$ 0.83	0.89	0.88	1.31	3.91	$ 1.05	0.63	0.55	1.01	3.24
Net income per common share — assuming dilution	$ 0.83	0.88	0.88	1.30	3.89	$ 1.05	0.62	0.55	1.01	3.23
Dividends per common share	$ 0.25	0.27	0.27	0.27	1.06	$ 0.23	0.25	0.25	0.25	0.98
Common stock prices										
High	$ 43.40	45.53	49.79	52.05	52.05	$ 36.60	38.45	38.50	41.13	41.13
Low	$ 39.91	41.43	44.20	48.18	39.91	$ 31.58	34.20	34.90	35.05	31.58

(1) *Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.*

(2) *Gross profit equals sales and other operating revenue less estimated costs associated with products sold.*

The price range of ExxonMobil common stock is as reported on the composite tape of the several U.S. exchanges where ExxonMobil common stock is traded. The principal market where ExxonMobil common stock (XOM) is traded is the New York Stock Exchange, although the stock is traded on other exchanges in and outside the United States.

There were 637,416 registered shareholders of ExxonMobil common stock at December 31, 2004. At January 31, 2005, the registered shareholders of ExxonMobil common stock numbered 636,250.

On January 26, 2005, the Corporation declared a $0.27 dividend per common share, payable March 10, 2005.

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OPERATING SUMMARY

	2004	2003	2002	2001	2000
	(thousands of barrels daily)				
Production of crude oil and natural gas liquids					
Net production					
United States	557	610	681	712	733
Canada	355	363	349	331	304
Europe	583	579	592	653	704
Asia Pacific	202	237	260	247	253
Africa	572	442	349	342	323
Other Non-U.S.	302	285	265	257	236
Worldwide	2,571	2,516	2,496	2,542	2,553
	(millions of cubic feet daily)				
Natural gas production available for sale					
Net production					
United States	1,947	2,246	2,375	2,598	2,856
Canada	972	943	1,024	1,006	844
Europe	4,614	4,498	4,463	4,595	4,463
Asia Pacific	1,519	1,803	2,019	1,547	1,755
Other Non-U.S.	812	629	571	533	425
Worldwide	9,864	10,119	10,452	10,279	10,343
	(thousands of oil-equivalent barrels daily)				
Oil-equivalent production [(1)]	4,215	4,203	4,238	4,255	4,277
	(thousands of barrels daily)				
Refinery throughput					
United States	1,850	1,806	1,834	1,811	1,862
Canada	468	450	447	449	451
Europe	1,663	1,566	1,539	1,563	1,578
Asia Pacific	1,423	1,390	1,379	1,436	1,462
Other Non-U.S.	309	298	244	283	289
Worldwide	5,713	5,510	5,443	5,542	5,642
Petroleum product sales					
United States	2,872	2,729	2,731	2,751	2,669
Canada	615	602	593	585	577
Europe	2,139	2,061	2,042	2,079	2,129
Asia Pacific and other Eastern Hemisphere	2,080	2,075	1,889	2,024	2,090
Latin America	504	490	502	532	528
Worldwide	8,210	7,957	7,757	7,971	7,993
Gasoline, naphthas	3,301	3,238	3,176	3,165	3,122
Heating oils, kerosene, diesel oils	2,517	2,432	2,292	2,389	2,373
Aviation fuels	698	662	691	721	749
Heavy fuels	659	638	604	668	694
Specialty petroleum products	1,035	987	994	1,028	1,055
Worldwide	8,210	7,957	7,757	7,971	7,993
	(thousands of metric tons)				
Chemical prime product sales					
United States	11,521	10,740	11,386	11,078	11,736
Non-U.S.	16,267	15,827	15,220	14,702	13,901
Worldwide	27,788	26,567	26,606	25,780	25,637

Operating statistics include 100 percent of operations of majority-owned subsidiaries; for other companies, crude production, gas, petroleum product and chemical prime product sales include ExxonMobil's ownership percentage, and refining throughput includes quantities processed for ExxonMobil. Net production excludes royalties and quantities due others when produced, whether payment is made in kind or cash.

(1) *Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.*

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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.

EXXON MOBIL CORPORATION

By: /s/ LEE R. RAYMOND

(Lee R. Raymond,
Chairman of the Board)

Dated February 28, 2005

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Richard E. Gutman, Robert E. Harayda and Brian A. Maher, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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 and on the dates indicated.

/s/ LEE R. RAYMOND (Lee R. Raymond)	Chairman of the Board (Principal Executive Officer)	February 28, 2005
/s/ MICHAEL J. BOSKIN (Michael J. Boskin)	Director	February 28, 2005
/s/ JAMES R. HOUGHTON (James R. Houghton)	Director	February 28, 2005

/s/ WILLIAM R. HOWELL (William R. Howell)	Director	February 28, 2005
/s/ REATHA CLARK KING (Reatha Clark King)	Director	February 28, 2005
/s/ PHILIP E. LIPPINCOTT (Philip E. Lippincott)	Director	February 28, 2005
/s/ HENRY A. MCKINNELL, JR. (Henry A. McKinnell, Jr.)	Director	February 28, 2005
/s/ MARILYN CARLSON NELSON (Marilyn Carlson Nelson)	Director	February 28, 2005
/s/ WALTER V. SHIPLEY (Walter V. Shipley)	Director	February 28, 2005
/s/ REX W. TILLERSON (Rex W. Tillerson)	Director	February 28, 2005
/s/ PATRICK T. MULVA (Patrick T. Mulva)	Controller (Principal Accounting Officer)	February 28, 2005
/s/ DONALD D. HUMPHREYS (Donald D. Humphreys)	Treasurer (Principal Financial Officer)	February 28, 2005

INDEX TO EXHIBITS

3(i).	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
3(ii).	By-Laws, as revised to July 31, 2002 (incorporated by reference to Exhibit 3(ii) to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
10(iii)(a.1).	2003 Incentive Program (incorporated by reference to Appendix B to the Proxy Statement of Exxon Mobil Corporation dated April 17, 2003).*
10(iii)(a.2).	Form of stock option granted to executive officers.*
10(iii)(a.3).	Form of restricted stock agreement with executive officers (incorporated by reference to Exhibit 99.4 to the Registrant's Report on Form 8-K on November 29, 2004).*
10(iii)(b.1).	Short Term Incentive Program, as amended (incorporate by reference to Exhibit 10(iii)(e) to the registrant's Annual Report on Form 10-K for 2003).*
10(iii)(b.2).	Form of Earnings Bonus Unit granted to executive officers (incorporated by reference to Exhibit 99.2 to the Registrant's Report on Form 8-K on November 29, 2004).*
10(iii)(c.1).	ExxonMobil Supplemental Savings Plan.*
10(iii)(c.2).	ExxonMobil Supplemental Pension Plan.*
10(iii)(c.3).	ExxonMobil Additional Payments Plan.*
10(iii)(d).	ExxonMobil Executive Life Insurance and Death Benefit Plan.*
10(iii)(e.1).	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Appendix B to the Proxy Statement of Exxon Mobil Corporation dated April 14, 2004).*
10(iii)(e.2).	Standing resolution for non-employee director restricted grants dated July 28, 2004 (incorporated by reference to Exhibit 10(iii)(c.2) to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004).*
10(iii)(e.3).	Form of restricted stock grant letter for non-employee directors (incorporated by reference to Exhibit 99.3 to the registrant's Report on Form 8-K on January 4, 2005).*
10(iii)(f.1).	Standing resolution for non-employee director cash fees dated September 27, 2000.*
10(iii)(f.2).	2001 Nonemployee Directors' Deferred Compensation Plan (incorporated by reference to Exhibit 10(iii)(b) to the registrant's Annual Report on Form 10-K for 2000).*

INDEX TO EXHIBITS—(continued)

10(iii)(g.1).	1995 Mobil Incentive Compensation and Stock Ownership Plan (incorporated by reference to Exhibit 10(iii)(g) to the registrant's Annual Report on Form 10-K for 2000).*
10(iii)(g.2).	Form of stock option granted to Mobil executive officers.*
12.	Computation of ratio of earnings to fixed charges.
14.	Code of Ethics and Business Conduct (incorporated by reference to Exhibit 14 to the registrant's Annual Report on Form 10-K for 2003).
21.	Subsidiaries of the registrant.
23.	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31.1	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.
31.2	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting Officer.
31.3	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Financial Officer.
32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.
32.2	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Financial Officer.

* Compensatory plan or arrangement required to be identified pursuant to Item 15(a)(3) of this Annual Report on Form 10-K.

The registrant has not filed with this report copies of the instruments defining the rights of holders of long-term debt of the registrant and its subsidiaries for which consolidated or unconsolidated financial statements are required to be filed. The registrant agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon request.

Exhibit 10(iii)(a.2)

EXXON MOBIL CORPORATION
STOCK OPTION

Option No.:	Name of Grantee:	Number of Shares of Stock subject to this Option:	Option Price Per Share

This **STOCK OPTION** ("Option"), dated November 28, 2001, is granted in Dallas County, Texas by Exxon Mobil Corporation (the "Corporation"), pursuant to the 1993 Incentive Program adopted by the shareholders of the Corporation on April 28, 1993, as amended (the "Program"). This Option is subject to the provisions of this instrument and the Program and to such regulations or requirements as may be stipulated from time to time by the administrative authority defined in the Program and is granted on the condition that Grantee accepts such provisions, regulations and requirements. This instrument incorporates by reference the provisions of the Program, as it may be amended from time to time, including without limitation the definitions of terms in this instrument and defined in the Program. This Option is not an Incentive Stock Option as defined in the Program.

1. Grant. The Corporation has granted to the Grantee named above an option to purchase from the Corporation shares of its common stock, without par value, up to the maximum number and at the option price per share set forth above, payable in currency of the United States of America, in shares of common stock of the Corporation or other consideration in accordance with the terms of the Program and any applicable regulations of the administrative authority in effect at the time. Such consideration will be valued at fair market value on the date of exercise.

2. Exercisability. Subject to paragraph 4, this Option shall become exercisable the earlier of one year after its date or upon the death of Grantee; provided that this Option shall never be exercisable whenever the purchase or delivery of shares under this Option would be a violation of any law or any governmental regulation which the Corporation may find to be applicable.

3. Date of Exercise and Payment of Taxes. The date of any exercise of this Option shall be the day on which all documents for a valid exercise are accepted by the Corporation. Grantee may elect to pay in shares of common stock of the Corporation a portion or all of the amount of the taxes required or permitted by federal, state, or local law to be withheld in connection with the exercise of this Option. To make such election, Grantee will agree to surrender to the Corporation, on or about the date such withholding tax liability is determinable, shares previously owned by Grantee having a fair market value equal to the amount of such withholding taxes that Grantee elects to pay in shares.

4. Expiration. This Option shall expire at the earliest of the following times:

(a) If Grantee terminates, but does not terminate normally, it shall expire at the time of termination.

(b) If Grantee engages in detrimental activity, it shall expire as of the date such activity is determined to be detrimental.

(c) If Grantee dies, it shall expire five years after death.

(d) In any event, it shall expire ten years after its date.

5. Partial Exercise and Adjustments. When this Option is exercisable for any whole number of shares up to the maximum number indicated above. This Option shall be adjusted by the administrative authority as it deems appropriate for any split, stock dividend, or other relevant change in capitalization of the Corporation.

6. Repayment of Amount Equal to Spread. If Grantee terminates other than normally, the granting authority may require Grantee to repay to the Corporation an amount equal to the spread on this Option at exercise if it is exercised in whole or in part by Grantee during the six-month period immediately preceding such termination.

7. Nontransferability. This Option is not transferable except by will or the laws of descent and distribution, and is not subject, in whole or in part, to attachment, execution or levy of any kind.

8. Governing Law and Consent to Jurisdiction . This Option and Program are governed by the laws of the State of New York without regard to any conflict of law rules. Any dispute arising out of or relating to this Option or the Program may be resolved in any state or federal court located within Dallas County, Texas, U.S.A. This Option is issued on the condition that Grantee accepts such venue and submits to the personal jurisdiction of any such court. Similarly, the Corporation accepts such venue and submits to such jurisdiction.

EXXON MOBIL CORPORATION

By

EXXONMOBIL SUPPLEMENTAL SAVINGS PLAN

(Including Key Employee Supplemental Savings Plan)

Edition of March 1, 2000

1. Purpose

The purpose of this Plan is to provide a payment of approximately equivalent value from the general assets of Exxon Mobil Corporation ("Corporation") to a person participating in the ExxonMobil Savings Plan ("Savings Plan") who, because of the application of United States Internal Revenue Code ("Code") sections 415 and 401(a)(17) is precluded from receiving employer contributions to the person's Savings Plan account to which the person would otherwise be entitled.

2. Benefits

2.1 Benefit Formula

As to any specific Savings Plan participant the total amount of payment under this Plan is an amount that is in general determined by notionally crediting on a monthly basis the amount of employer contributions that cannot be made to the Savings Plan for that person as a result of application to that person of Code sections 415 and 401(a)(17); except that, for those persons who, as of December 31, 1993, are classified at level 36 and are age 50 and above, only notional employer contributions made after such date are taken into account. This amount is enhanced in each instance by the Citibank Prime Lending Rate as of the last business day of each calendar quarter, and is then reduced, but not below zero, by the amount, if any, of the actuarial lump-sum value of the amount payable to the participant under the ExxonMobil Key Employee Additional Payments Plan that is not applied as an offset against the participant's benefit under the ExxonMobil Additional Payments Plan or the ExxonMobil Supplemental Pension Plan. For this purpose, the actuarial lump-sum value shall be determined using the mortality and interest rate assumptions set out in the ExxonMobil Pension Accounts Instrument.

2.2 Calculation Methodology

The exact methodology used in determining such monthly credits and interest thereon will be established from time to time by the Plan Administrator. General guidelines to be followed are

(A) Required Participant Contributions

To the extent determined by those administering this Plan, a person is required to make regular employee contributions to the person's Savings Plan account up to the maximum permitted by the Code to receive credits under this Plan.

(B) Discretionary Employee Contributions

Prior to July 1, 2002, a person may not enhance the amounts credited under this Plan by making discretionary employee contributions to the person's Savings Plan account.

(C) Additional Contributions under Leveraged ESOP

No amount is credited under this Plan because of a person's inability to obtain all or a portion of the enhanced portion of the employer match for employer matches directed to a leveraged ESOP.

3. Payment of Benefits

3.1 Form of Payment

(A) In General

Payments under this Plan are normally in the form of a lump sum single payment but, in the sole discretion of the Corporation, may be made in any other form that is not greater than the actuarial equivalent of the single lump sum form of payment.

(B) Actuarial Equivalence

For purposes of paragraph (A), actuarial equivalency is determined by the Plan Administrator using the factors used for comparable determinations under the ExxonMobil Pension Plan.

3.2 Timing of Payment

(A) Distribution upon Total Savings Plan Distribution

Except as provided in paragraphs (B)-(E) below, payments under this Plan shall occur as soon as practicable following the time of the participant's entire Savings Plan account is distributed in a final distribution.

(B) Restrictions on K Account Distribution

If a participant's entire Savings Plan account cannot be distributed on account of restrictions on the distribution of the K Account, payments under this Plan shall occur at the same time as the participant's entire Savings Plan account, other than the K Account, is distributed.

(C) Small Accounts

If the total amount to be paid to a participant under this Plan and the ExxonMobil Key Employee Supplemental Savings Plan is in the aggregate $25,000 or less, determined at the time of termination of employment from Exxon Mobil Corporation and its affiliates, payments under this Plan shall occur as soon as practicable after the participant terminates employment.

(D) Infineum Employees

If a participant's Savings Plan account is transferred to a savings plan sponsored by Infineum USA Inc. or any of its affiliates ("Infineum"), payments under this Plan shall occur as soon as practicable after the participant terminates employment from Infineum.

(E) Divestitures

The Plan Administrator shall determine when distributions shall be made to former employees whose employment is terminated in connection with corporate divestitures. Such determinations shall be made in accordance with management guidelines established in connection with such divestitures.

4. Beneficiaries

4.1 Designation of Beneficiaries

A person entitled to receive a payment under this Plan may name one or more designated beneficiaries to receive such payment in the event of the person's death. Beneficiary designations shall be made in accordance with such procedures as the Plan Administrator may establish. Spousal consent to any designation is not required.

4.2 Default Beneficiaries

(A) In General

If no specific designation is in effect, the deceased's beneficiary is the person or persons in the first of the following classes of successive beneficiaries living at the time of death of the deceased:

(1) spouse;

(2) children who survive the participant or who die before the participant leaving children of their own who survive the participant;

(3) parents;

(4) brothers and sisters who survive the participant or who die before the participant leaving children of their own who survive the participant.

If there are no members of any class of such beneficiaries, payment is made to the deceased's executors or administrators.

(B) Allocation among Default Beneficiaries

If the same class of beneficiaries under paragraph (A) above contains two or more persons, they share equally, with further subdivision of such equal shares as next provided. In class (2), where a child dies before the participant leaving children who survive the participant, such child's share is subdivided equally among those children. In class (4), where a brother or sister dies before the participant leaving children who survive the participant, such brother or sister's share is subdivided equally among those children.

(C) Definitions

For purposes of this Section 4.2, "child" means a person's son or daughter by legitimate blood relationship or legal adoption; "parent" means a person's father or mother by legitimate blood relationship or legal adoption; "brother" or "sister" means another child of either or both of one's parents.

5. Miscellaneous

5.1 Administration of Plan

The Plan Administrator shall be the Manager, Executive Programs, Human Resources Department, Exxon Mobil Corporation. The Plan Administrator shall have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person's eligibility for benefits hereunder.

5.2 Nature of Payments

Payments provided under this Plan are considered general obligations of the Corporation.

5.3 Assignment or Alienation

Except as provided in section 5.5 below, payments provided under this Plan may not be assigned or otherwise alienated or pledged.

5.4 Amendment or Termination

The Corporation reserves the right to amend or terminate this plan, in whole or in part, including the right at any time to reduce or eliminate any accrued benefits hereunder and to alter or amend the benefit formula set out herein.

5.5 Forfeiture of Benefits

No person shall be entitled to receive payments under this Plan and any payments received under this Plan shall be forfeited and returned if it is determined by the Corporation in its sole discretion, acting through its chief executive or such person or committee as the chief executive may designate, that a person otherwise entitled to a payment under this Plan or who has commenced receiving payments under this Plan:

(A) engaged in gross misconduct harmful to the Corporation,

(B) committed a criminal violation harmful to the Corporation,

(C) had concealed actions described in paragraph (A) or (B) above which would have brought about termination from employment thereby making the person ineligible for benefits under this Plan,

(D) terminated employment prior to attaining age 65 without having received from the Corporation or its delegatee prior written approval for such termination, given in the sole discretion of the Corporation or its delegatee and in the context of recognition that benefits under this Plan would not be forfeited upon such termination, or

(E) had been terminated for cause.

EXXONMOBIL KEY EMPLOYEE SUPPLEMENTAL SAVINGS PLAN

K1. Purpose

This Plan provides a payment from the general assets of Exxon Mobil Corporation ("Corporation") to a person who, as of December 31, 1993,

(A) was classified at level 36 or above,

(B) was age 50 or above,

(C) was a participant in the Thrift Plan of Exxon Corporation ("Thrift Plan"), and

(D) had been precluded from receiving employer contributions to the person's account within the Thrift Plan to which the person would otherwise be entitled, because of the application of United States Internal Revenue Code ("Code") sections 415 and 401(a)(17).

This plan expresses the Corporation's commitment to make such a payment at the time payment is made to the participant under the ExxonMobil Supplemental Savings Plan, and sets forth the method for doing so.

K2. Benefits

K2.1 Benefit Formula

As to a participant, the total amount of payment under this Plan shall be an amount that has been in general determined by notionally crediting on a monthly basis the amount of employer contributions that could not have been made to the Thrift Plan account of that person as a result of application to that person of Code sections 415 and 401(a)(17) from the date the person otherwise would have been an eligible participant in the Exxon Supplemental Thrift Plan until December 30, 1993. This amount shall be enhanced in each instance by the Citibank Prime Lending Rate as of the last business day of each calendar quarter. A participant in this Plan shall have a non-forfeitable right to this amount credited as of December 31, 1993 plus all enhancements.

K2.2 Calculation Methodology

The exact methodology for such notional credits and interest thereon shall be determined by the Plan Administrator.

K3. Payment of Benefits

K3.1 Form of Payment

(A) In General

Payments under this Plan are made normally in the form of a lump sum single payment but, in the sole discretion of the Corporation, may be made at any time or times subsequent to entitlement and in any other form that is not greater than the actuarial equivalent of the single lump sum form of payment.

(B) Actuarial Equivalence

For purposes of Paragraph (A), actuarial equivalency is determined by the Plan Administrator using the factors used for comparable determinations under the ExxonMobil Pension Plan.

K3.2 Timing of Payment

Payment shall be made under this Plan at the same time as payment is made to the participant under the ExxonMobil Supplemental Savings Plan.

K4. Beneficiaries

K4.1 Designation of Beneficiaries

A person entitled to receive a payment under this Plan may name one or more designees to receive such payment in the event of the person's death. Beneficiary designations shall be made in accordance with such procedures as the Plan Administrator may establish. Spousal consent to any designation is not required.

K4.2 Default Beneficiaries

(A) In General

If no specific designation is in effect, the deceased's beneficiary is the person or persons in the first of the following classes of successive beneficiaries living at the time of death of the deceased:

(1) spouse;

(2) children who survive the participant or who die before the participant leaving children of their own who survive the participant;

(3) parents;

(4) brothers and sisters who survive the participant or who die before the participant leaving children of their own who survive the participant.

If there are no members of any class of such beneficiaries, payment is made to the deceased's executors or administrators.

(B) Allocation among Default Beneficiaries

If the same class of beneficiaries under paragraph (A) above contains two or more persons, they share equally, with further subdivision of such equal shares as next provided. In class (2), where a child dies before the participant leaving children who survive the participant, such child's share shall be subdivided equally among those children. In class (4), where a brother or sister dies before the participant leaving children who survive the participant, such brother or sister's share shall be subdivided equally among those children.

(C) Definitions

For purposes of this Section K4.2, "child" means a person's son or daughter by legitimate blood relationship or legal adoption; "parent" means a person's father or mother by legitimate blood relationship or legal adoption; “brother” or “sister” means another child of either or both of one’s parents.

K5. Miscellaneous

K5.1 Administration of Plan

The Plan Administrator shall be the Manager, Executive Programs, Human Resources Department, ExxonMobil Corporation. The Plan Administrator shall have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person’s eligibility for benefits hereunder.

K5.2 Nature of Payments

Payments provided under this Plan shall be considered general obligations of the Corporation.

K5.3 Assignment or Alienation

Payments provided under this Plan may not be assigned or otherwise alienated or pledged.

K5.4 Amendment or Termination

The Corporation may at any time amend or terminate this Plan, in whole or in part, so long as the amendment does not deprive any person of the non-forfeitable right to benefits specifically granted in this Plan.

EXXONMOBIL SUPPLEMENTAL PENSION PLAN

(Including Key Employee Supplemental Pension Plan)

Edition of March 1, 2000

1. Purpose

The purpose of this Plan is to provide payments of equivalent value from the general assets of Exxon Mobil Corporation ("Corporation") to those participants in the ExxonMobil Pension Plan ("Pension Plan") who, because of the application of United States Internal Revenue Code ("Code") sections 415 and 401(a)(17), are precluded from receiving from Pension Plan funded assets all the payments to which they would otherwise be entitled under the Pension Plan's formula.

2. Benefits

2.1 Benefit Formula

(A) In General

Except as provided in paragraph (B) below with respect to former Mobil employees, as defined in the ExxonMobil Common Provisions, ("Former Mobil Employees"), as to any Pension Plan participant eligible for payment under this Plan, the value of the payments under this Plan is an amount that when added to the normal form amount that can be paid to the participant from the Pension Plan's qualified funded assets, produces a sum equal to the total normal form amount to which the participant would be entitled computed under the Pension Plan formula applicable to that participant disregarding any reductions, restrictions, or limitations brought about by the application of Code sections 415 and 401(a)(17), reduced, but not below zero, by the following amounts:

(1) the amount, if any, payable to the participant under the ExxonMobil Key Employee Supplemental Pension Plan, and

(2) the amount, if any, payable to the participant under the ExxonMobil Key Employee Additional Payments Plan that is not applied as an offset against the participant's benefit under the ExxonMobil Additional Payments Plan.

Where relevant, this computation is performed after taking into account any entitlement the participant may have under the Overseas Contributory Annuity Plan.

(B) Benefit Formula for Former Mobil Employee

The payments under this Plan for Former Mobil Employees who retire with eligibility for Incentive Pension Benefits under the ExxonMobil Additional Payments Plan shall be the amounts determined under paragraph (1) below and, if applicable, paragraph (2) below.

(1) In General

The amount benefit determined under this paragraph (1) shall be the lesser of:

(a) the amount of the person's benefit otherwise determined under paragraph (A) above, or

(b) the excess if any of the person's Overall Benefit Objective as described in section 2.3(B) of the ExxonMobil Additional Payments Plan, over the sum of the person's benefit under the ExxonMobil Pension Plan (including any Pre-Social Security Benefit) and the person's Incentive Pension Benefit and Nonqualified PSSP Benefit, if any, as determined under the ExxonMobil Additional Payments Plan.

(2) Nonqualified PSSP Benefits

The amount of a person's benefit determined under this paragraph (2) shall be the amount, if any, of any Nonqualified PSSP Benefit determined for such person under the terms of the ExxonMobil

Additional Payments Plan. Such Nonqualified PSSP Benefit shall be paid in accordance with the rules applicable to the payment of the Pre-Social Security Pension benefit under the ExxonMobil Pension Plan.

2.2 Offsets for Other Pension Benefits

A person's benefit determined under section 2.1 shall be offset, but not below zero, by any benefit payable to the person under (A) an offsetting pension that is not qualified under the terms of the U.S. Internal Revenue Code, (B) a separation payment offset, or (C) a non-U.S. governmental pension offset, as such terms are defined under the ExxonMobil Pension Plan.

2.3 Plan Administrator Discretion

The procedure for calculating the benefit for former Mobil employees under section 2.1 above, and for determining the application of the offsets for other pension benefits under section 2.2 above, shall be determined in the sole and exclusive discretion of the Plan Administrator.

2.4 Benefits Payable On Account of Death

(A) In General

In the event a portion of a pension death benefit or a "Career Annuity subject to deferred commencement that commences by reason of death" that becomes payable under the terms of the Pension Plan on account of the death of a participant cannot be paid to a beneficiary because of the application of Code sections 415 and 401(a)(17), compensating payments of equivalent value are provided to such beneficiary under this Plan, the exact nature and amounts of which shall be determined under a methodology established from time to time by the Plan Administrator. Specifically, the Plan Administrator may limit the amount of such payments to reflect the benefit formula applicable to Former Mobil Employees set out in section 2.1(B) above.

(B) Excluded Benefits

Neither the Qualified Joint and Survivor Annuity payment option, nor the Surviving Spouse Annuity benefit, as such are provided for under the Pension Plan, are provided as benefits under this Plan.

3. Beneficiaries

3.1 Designation of Beneficiaries

A person may name one or more designated beneficiaries to receive the benefits payable under this Plan under section 2.2 above in the event of the person's death. Beneficiary designations shall be made in accordance with such procedures as the Plan Administrator may establish. Spousal consent to any designation is not required.

3.2 Default Beneficiaries

(A) In General

If no specific designation is in effect, the deceased's beneficiary is the person or persons in the first of the following classes of successive beneficiaries living at the time of death of the deceased:

(1) spouse;

(2) children who survive the participant or who die before the participant leaving children of their own who survive the participant;

(3) parents;

(4) brothers and sisters who survive the participant or who die before the participant leaving children of their own who survive the participant.

If there are no members of any class of such beneficiaries, payment is made to the deceased's executors or administrators.

(B) Allocation among Default Beneficiaries

If the same class of beneficiaries under paragraph (A) above contains two or more persons, they share equally, with further subdivision of such equal shares as next provided. In class (2), where a child dies before the participant leaving children who survive the participant, such child's share is subdivided equally among those children. In class (4), where a brother or sister dies before the participant leaving children who survive the participant, such brother or sister's share is subdivided equally among those children.

(C) Definitions

For purposes of this section 3.2, "child" means a person's son or daughter by legitimate blood relationship or legal adoption; "parent" means a person's father or mother by legitimate blood relationship or legal adoption; "brother" or "sister" means another child of either or both of one's parents.

4. Payment of Benefits

4.1 Commencement of Benefits

(A) In General

Payments under this Plan occur at the same time as payments under the Pension Plan commence.

(B) Reduction for Early Commencement

If payments under this Plan commence prior to the month in which the person reaches age 65, they are reduced by applying the early commencement factors applicable to the person under the Pension Plan. For all actuarial purposes, this monthly amount paid as a five-year certain life annuity is deemed the normal form amount.

4.2 Form of Payment

(A) In General

Payments under this Plan other than payments to designated beneficiaries are made normally in the form of a five year certain life annuity, but, in the sole discretion of the Corporation, may be made in any other form, including a joint and survivor form, that is not greater than the actuarial equivalent of the normal form amount.

(B) Actuarial Equivalence

For purposes of paragraph (A), actuarial equivalency is determined by the Plan Administrator using the factors used for comparable determinations under the Pension Plan.

5. Miscellaneous

5.1 Administration of Plan

The Plan Administrator shall be the Manager, Executive Programs, Human Resources Department, Exxon Mobil Corporation. The Plan Administrator shall have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person's eligibility for benefits hereunder.

5.2 Nature of Payments

Payments provided under this Plan are considered general obligations of the Corporation.

5.3 Assignment or Alienation

Except as provided in section 5.5 below, payments provided under this Plan may not be assigned or otherwise alienated or pledged.

5.4 Amendment or Termination

The Corporation reserves the right to amend or terminate this Plan, in whole or in part, including the right at any time to reduce or eliminate any accrued benefits hereunder and to alter or amend the benefit formula set out herein.

5.5 Forfeiture of Benefits

No person shall be entitled to receive payments under this Plan and any payments received under this Plan shall be forfeited and returned if it is determined by the Corporation in its sole discretion, acting through its chief executive or such person or committee as the chief executive may designate, that a person otherwise entitled to a payment under this Plan or who has commenced receiving payments under this Plan:

(A) engaged in gross misconduct harmful to the Corporation,

(B) committed a criminal violation harmful to the Corporation,

(C) had concealed actions described in paragraph (A) or (B) above which would have brought about termination from employment thereby making the person ineligible for benefits under this Plan,

(D) terminated employment prior to attaining age 65 without having received from the Corporation or its delegatee prior written approval for such termination, given in the sole discretion of the Corporation or its delegatee and in the context of recognition that benefits under this Plan would not be forfeited upon such termination, or

(E) had been terminated for cause.

EXXONMOBIL KEY EMPLOYEE SUPPLEMENTAL PENSION PLAN

K1. Purpose

This Plan provides payments from the general assets of Exxon Mobil Corporation ("Corporation") to those persons who, as of December 31, 1993,

(A) were classified at level 36 or above,

(B) were age 50 and above, and

(C) were participants in the Annuity Plan of Exxon Corporation ("Annuity Plan") and who, because of the application of United States Internal Revenue Code ("Code") sections 415 and 401(a)(17), would have been precluded from receiving from Annuity Plan funded assets all the payments to which they would otherwise be entitled under the Annuity Plan's formula.

This Plan expresses the Corporation's commitment to provide such equivalent payments and sets forth the method for doing so.

K2. Benefits

K2.1 Benefit Formula

As to any participant eligible for payment under this Plan, the value of such payments shall be an amount that when added to the normal form amount that could have been paid to the participant from the Annuity Plan's qualified funded assets, produces a sum equal to the total normal form amount to which the participant would have been entitled computed under the Annuity Plan formula applicable to that participant as of December 31, 1993, disregarding any reductions, restrictions, or limitations brought about by Code sections 415 and 401(a)(17). Where relevant, all computations will take into account any entitlement the participant may have under the Overseas Contributory Annuity Plan. A participant in this Plan shall have a non-forfeitable right to this amount.

K2.2 Benefit Payable On Account of Death

(A) Death Benefit

In the event a pension death benefit is payable under the terms of the ExxonMobil Pension Plan ("Pension Plan") on account of the death of a participant, a death benefit shall be payable under this Plan equal to the lump-sum value of the benefit that would have been payable under section K2.1 above to the participant if the participant had not died but had terminated employment and had elected to commence his or her benefit as of the date of death.

(B) Deferred Annuity Death Benefit

In the event a "Career Annuity subject to deferred commencement that commences by reason of death" is payable under the terms of the Pension Plan on account of the death of a participant, a similar benefit shall be payable under this Plan based on the benefit that would have been payable under section K2.1 above to the participant if the participant had not died.

(C) Calculation Methodology

The exact nature and amounts of any benefit payable under paragraph (A) or (B) shall be determined under a methodology established from time to time by the Plan Administrator.

(D) Excluded Benefits

Specifically excluded from coverage and entitlement under this Plan are:

(1) the legally mandated Qualified Joint and Survivor Annuity, and

(2) the right to elect a Surviving Spouse Annuity

as such are established for married participants in the Pension Plan.

K3. Beneficiaries

K3.1 Designation of Beneficiaries

A person entitled to receive benefits under this Plan may name one or more designated beneficiaries to receive the benefits payable under this Plan under section K2.2 above in the event of the person's death in accordance with such procedures as the Plan Administrator may establish. Spousal consent to any designation in not required.

K3.2 Default Beneficiaries

(A) In General

If no specific designation is in effect, the deceased's beneficiary is the person or persons in the first of the following classes of successive beneficiaries living at the time of death of the deceased:

(1) spouse;

(2) children who survive the participant or who die before the participant leaving children of their own who survive the participant;

(3) parents;

(4) brothers and sisters who survive the participant or who die before the participant leaving children of their own who survive the participant.

If there are no members of any class of such beneficiaries, payment is made to the deceased's executors or administrators.

(B) Allocation among Default Beneficiaries

If the same class of beneficiaries under paragraph (A) above contains two or more persons, they share equally, with further subdivision of such equal shares as next provided. In class (2), where a child dies before the participant leaving children who survive the participant, such child's share shall be subdivided equally among those children. In class (4), where a brother or sister dies before the participant leaving children who survive the participant, such brother or sister's share shall be subdivided equally among those children.

(C) Definitions

For purposes of this section K3.2, "child" means a person's son or daughter by legitimate blood relationship or legal adoption; "parent" means a person's father or mother by legitimate blood relationship or legal adoption; "brother" or "sister" means another child of either or both of one's parents.

K4. Payment of Benefits

K4.1 Commencement of Benefits

(A) In General

Payments under this Plan occur at the same time as payments under the ExxonMobil Supplemental Pension Plan commence.

(B) Reduction for Early Commencement

If payments under this Plan commence prior to the month in which the person reaches age 65, they are reduced by applying the early commencement factors for retirees set forth in the Pension Plan for a normal maturity age of 65. For all actuarial purposes, this monthly amount paid as a five-year certain life annuity is deemed the normal form amount.

K4.2 Form of Payment

(A) In General

Payments under this Plan other than payments to designated beneficiaries are made normally in the form of a five year certain life annuity, but, in the sole discretion of the Corporation, may be made in any other form, including a joint and survivor form, that is not greater than the actuarial equivalent of the normal form amount.

(B) Actuarial Equivalence

For purposes of paragraph (A), actuarial equivalency is determined by the Plan Administrator using the factors used for comparable determinations under the Pension Plan.

K5. Miscellaneous

K5.1 Administration of Plan

The Plan Administrator shall be the Manager, Executive Programs, Human Resources Department, ExxonMobil Corporation. The Plan Administrator shall have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person's eligibility for benefits hereunder.

K5.2 Nature of Payments

Payments provided under this Plan shall be considered general obligations of the Corporation.

K5.3 Assignment or Alienation

Payments provided under this Plan may not be assigned or otherwise alienated or pledged.

K5.4 Amendment or Termination

The Corporation reserves the right to amend or terminate this Plan, in whole or in part, so long as the amendment does not deprive any person of the non-forfeitable right to benefits specifically granted in this Plan.

EXXONMOBIL ADDITIONAL PAYMENTS PLAN

(Including Key Employee Additional Payments Plan)

Edition of March 1, 2000

1. Purpose

The purpose of this Plan is to provide additional payments from the general assets of Exxon Mobil Corporation (the "Corporation") to certain persons. For an individual participant, the benefit payable under this Plan consists of up to three parts. The first part is a benefit based upon the person's final average incentive compensation ("Incentive Pension Benefit"). The second part is the payment of an additional disability benefit ("Disability Retirement Benefit"). The third part is a makeup benefit based upon certain benefits otherwise promised but not received under a pension plan sponsored by a non-U.S. affiliate of the Corporation ("Overseas Makeup Benefit").

2. Incentive Pension Benefits

2.1 Eligibility

A person is eligible to receive Incentive Pension Benefits only if the person satisfies at least one of the following requirements:

(A) the person becomes a retiree within the meaning of the ExxonMobil Common Provisions ("retiree");

(B) the person terminates employment without becoming a retiree and

(1) is at least 50 years old by the end of the month in which the termination of employment occurs;

(2) has at least 10 years of benefit plan service (as determined under the ExxonMobil Common Provisions) at the time of the termination of employment; and

(3) receives a benefit under the Exxon Transition Severance Plan; or,

(C) in the case of an individual who after terminating employment from the Corporation or any of its affiliates continues employment with Infineum USA Inc. or one of its affiliates (collectively, “Infineum”), becomes a qualified plans retiree within the meaning of the ExxonMobil Common Provisions (“qualified plans retiree”).

Paragraph (B) above shall expire automatically and be of no further effect after nine months from the date of the merger of Exxon Corporation and Mobil Corporation. If, however, the merger date is other than the first day of a month, paragraph (B) shall expire as of the end of the month in which the nine-month anniversary of the merger date occurs.

2.2 Benefit Formula

(A) in General

Except as provided in section 2.3 below with respect to former Mobil employees, as defined in the ExxonMobil Common Provisions, (“Former Mobil Employees”) the amount of a person’s Incentive Pension Benefits is determined by multiplying 1.6% of the person’s final average incentive compensation by the person’s years of pensionable service as determined under the ExxonMobil Pension Plan, reduced, but not below zero, by the equivalent amount, if any, determined with respect to the person under the ExxonMobil Key Employee Additional Payments Plan. The amount so derived is an annual benefit which is divided by 12 and paid to the person in a monthly five-year certain and life annuity.

(B) Final Average Incentive Compensation

For the purposes of paragraph (A) above, a person’s “final average incentive compensation” shall be determined in accordance with this paragraph (B).

(1) Calculation

(a) In General

If a person's eligibility for Incentive Pension Benefits arises from section 2.1(A) or (B) above, the person's final average incentive compensation is the average of the person's three highest annual bonus awards (including awards of zero, if any) under the Corporation's Incentive Programs awarded on any of the five most recent annual award dates immediately preceding the person's termination of employment.

(b) Corporate Acquisitions

For purposes of applying paragraph (A) above to a person who commences employment with the Corporation or one of its affiliates in connection with a corporate acquisition, incentive compensation paid by the person's former employer that is the equivalent of bonus awards payable under the Corporation's Incentive Program may be taken into account as determined by the management of the Corporation in its sole discretion. Management shall have the discretion to exclude any and all prior employer compensation for purposes of this paragraph (b).

(2) Infineum Participants

If a person's eligibility for Incentive Pension Benefits arises from Section 2.1(C) above, the person's final average incentive compensation is the sum of the three highest annual bonus awards under the Corporation's Incentive Programs, if any, during the five-year period immediately prior to the person's termination of employment from Infineum, divided by three.

(3) Annual Bonus Award

(a) Items Used in Calculation

For purposes of this paragraph (B), in determining the amount of a person's annual bonus award, only awards granted under the short-term incentive part of the Incentive Programs as cash, unrestricted shares of stock, and bonus units are considered.

(b) Item Excluded From Calculation

For purposes of this paragraph (B), in determining the amount of a person's annual bonus award, an award to a person characterized by the granting authority as a special one-time bonus is disregarded, unless deemed specifically includable by the granting authority at the time of grant.

(c) Calculation of Annual Bonus Award

If an annual bonus award is granted as unrestricted shares of stock, the fair market value of such stock at the time of the award shall be used in calculating the value of the award. If an annual bonus award is granted as bonus units, the maximum settlement value obtainable at the time of the grant shall be used in calculating the value of the award.

2.3 Benefit Formula for Former Mobil Employee

(A) In General

Incentive Pension Benefits for Former Mobil Employees who retire with eligibility for Incentive Pension Benefits under section 2.1 above shall be determined under this section 2.3. The amount of a person's Incentive Pension Benefit calculated under this section 2.3 is the smaller of

(1) the amount of the person's Incentive Pension Benefit otherwise determined under section 2.2 above based on all of the person's pensionable service under the ExxonMobil Pension Plan, or

(2) the amount determined by first calculating the person's Overall Benefit Objective under paragraph (B) below, then subtracting therefrom the person's Qualified Benefit Objective calculated under paragraph (C) below and the person's nonqualified PSSP benefit, if any, determined under paragraph (D) below.

The resulting amount is expressed as a monthly five-year certain and life annuity.

(B) <u>Overall Benefit Objective</u>

(1) <u>In General</u>

A person's Overall Benefit Objective is the greater of

(a) the sum of the person's Mobil Benefit described in paragraph (2) below and the person's Post-Mobil Benefit described in paragraph (3) below, or

(b) the person's Overall ExxonMobil Benefit described in paragraph (4) below.

(2) <u>Mobil Benefit</u>

A person's Mobil Benefit is the person's accrued benefit under the Retirement Plan of Mobil Oil Corporation and the Supplemental Pension and Annuity Program of Mobil Oil Corporation up through the date the person becomes a participant in the ExxonMobil Pension Plan, based on service and compensation up through the date the person becomes a participant in the ExxonMobil Pension Plan.

(3) <u>Post-Mobil Benefit</u>

A person's Post-Mobil Benefit is the person's accrued benefit described in paragraph (4) below based only on the person's pensionable service after the person becomes a participant in the ExxonMobil Pension Plan.

(4) <u>Overall ExxonMobil Benefit</u>

A person's Overall ExxonMobil Benefit is the sum of

(a) the person’s accrued benefit under the ExxonMobil Pension Plan (including the Pre-Social Security Pension benefit) without any application of the limits under Code section 415 or 401(a)(17), and

(b) the amount of the person’s Incentive Pension Benefit otherwise determined under section 2.2 above,

based on all of the person’s pensionable service under the ExxonMobil Pension Plan.

(5) Rules for Calculation

In calculating a person’s Mobil Benefit, Post-Mobil Benefit and Overall ExxonMobil Benefit, the Plan administrator shall apply rules similar to those contained in section 2.7 of the ExxonMobil Pension Plan for purposes of calculating the person’s frozen Mobil benefit, post-Mobil benefit, and ExxonMobil benefit, respectively.

(C) Qualified Benefit Objective

A person’s Qualified Benefit Objective is the person’s accrued benefit under the ExxonMobil Pension Plan, including the person’s Pre-Social Security Pension.

(D) Nonqualified PSSP Benefit

A person’s Nonqualified PSSP Benefit is the excess, if any, of

(1) the amount of the person’s Pre-Social Security Pension benefit calculated in connection with the person’s Overall Benefit Objective under paragraph (B) above, over

(2) the amount of the person’s Pre-Social Security Pension benefit or the equivalent thereof under Part 2 of the ExxonMobil Pension Plan calculated in connection with the person’s Qualified Benefit Objective under paragraph (C) above.

(E) Plan Administrator Discretion

The procedure for calculating the Incentive Pension Benefit for former Mobil employees under this section 2.3, including the calculation of the benefit comparisons, offsets and reductions, shall be determined in the sole and exclusive discretion of the Plan Administrator. To the extent applicable, the Plan Administrator shall follow the procedures established under the ExxonMobil Pension Plan for performing similar benefit calculations.

2.4 Lapse of Incentive Pension Benefit

The portion of any Incentive Pension Benefit deriving from a provisionally granted bonus that is subsequently annulled lapses as of the date of such annulment.

3. Disability Retirement Benefit

3.1 Eligibility

If a person who becomes a retiree also becomes entitled to long-term disability benefits under the ExxonMobil Disability Plan, the person then receives monthly Disability Retirement Benefits under this Plan.

3.2 Benefit Formula

The amount of each monthly Disability Retirement Benefit payable to a person is determined by dividing one-half of the person's final average incentive compensation, determined under section 2.2(B) above, by 12 and deducting therefrom the normal form amount of any Incentive Pension Benefit or Overseas Makeup Benefit that the person has commenced receiving under this Plan.

3.3 Period of Payment

Payment of monthly Disability Retirement Benefits under this Plan shall commence at the time long-term disability benefits commence under the Disability Plan and shall continue as long as entitlement to long-term disability or transition benefits under the Disability Plan occurs.

4. Overseas Makeup Benefit

4.1 Eligibility

A person is eligible to receive an Overseas Makeup Benefit if the following conditions are met as determined by the Plan Administrator:

(A) the person accrues a benefit under a pension plan ("non-U.S. plan") sponsored by a non-U.S. affiliate of the Corporation;

(B) the person terminates active participation in the non-U.S. plan and simultaneously becomes a participant in the ExxonMobil Pension Plan or predecessor plan;

(C) as a result of terminating active participant status under the non-U.S. plan, the person loses eligibility for all or a portion of the benefit under the non-U.S. plan accrued prior to termination; and

(D) the amount of the lost benefit is not provided under the terms of the ExxonMobil Pension Plan, the ExxonMobil Supplemental Pension Plan, or otherwise under this Plan.

4.2 Benefit Formula

The amount of the Overseas Makeup Benefit is the amount, expressed as a monthly benefit in the form of a five-year certain and life annuity, that is the actuarial equivalent of the lost benefit under the non-U.S. plan. Such amount shall be conclusively determined by the Plan Administrator.

5. Payment of Benefits

5.1 Commencement of Benefits

(A) In General

Payments under this Plan, other than Disability Retirement Payments, occur at the same time as payments under the ExxonMobil Pension Plan commence.

(B) Reduction for Early Commencement

If payments under this Plan, other than Disability Retirement Payments, commence prior to the month in which the person reaches age 65, they are reduced by applying the early commencement factors applicable to the person's pension benefit under the ExxonMobil Pension Plan. For all actuarial purposes, this monthly amount paid as a five-year certain life annuity is deemed the normal form amount.

5.2 Form of Payment

(A) In General

Payments under this Plan, other than Disability Retirement Payments and payments to designated beneficiaries, are made normally in the form of a five-year certain life annuity, but, in the sole discretion of the Corporation, may be made in any other form that is not greater than the actuarial equivalent of the normal form amount.

(B) Determination of Actuarial Equivalency

For purposes of paragraph (A) above, actuarial equivalence is determined by the Plan Administrator using factors used for comparable determinations under the ExxonMobil Pension Plan.

5.3 Offset for Similar Benefits

If a participant under this Plan is also entitled to payments comparable to the Incentive Retirement Payments or the Disability Retirement Payments for any portion of the same years of pensionable service under a plan of a service-oriented employer, as defined in the ExxonMobil Common Provisions, other than the Corporation, the amount of the Incentive Retirement Payments or Disability Retirement Payments is reduced by the respective amount of such comparable payments. In any given case, the Plan Administrator may determine the precise amount of this offset and if a conversion of currency computation is required, may follow the process established under the ExxonMobil Pension Plan.

6. Death Benefits

6.1 In General

If a person dies who is described in section 6.2 below, the person's beneficiary (as determined under article 7 below) shall receive a death benefit described in section 6.3 below.

6.2 Eligibility

A person is described in this section 6.2 if, at the time of the person's death, the person

(A) was an active employee with 15 or more years of Benefit Plan Service, as determined under the ExxonMobil Common Provisions, or

(B) had retired with eligibility for Incentive Pension Payments or Mobil Wraparound Payments under this Plan and had not commenced receiving such payments.

6.3 Death Benefit

(A) In General

If a person described in section 6.2 above dies as an employee or as a retiree without eligibility for Disability Retirement Payments, the death benefit payable to the person's beneficiary shall be the sum of the following:

(1) the lump-sum equivalent value of the person's Incentive Retirement Payments, Overseas Makeup Payments and/or Mobil Wraparound Payments to which the person was or would have been entitled, plus

(2) the lump-sum equivalent value of 60 monthly Disability Retirement Payments determined under article 3 above, calculated as if the person had become eligible for such payments on the day prior to death and had commenced his or her Incentive Retirement Payments, Overseas Makeup Payments and/or Mobil Wraparound Payments on such date.

(B) Death After Commencement of Disability Retirement Payments

If a person described in section 6.2 above dies as a retiree while receiving Disability Retirement Payments but before the receipt of 60 monthly Disability Retirement Payments, the death benefit payable to the person's beneficiary shall be the sum of the following:

(1) the lump-sum equivalent value of the person's Incentive Retirement Payments, Overseas Makeup Payments and/or Mobil Wraparound Payments to which the person was or would have been entitled, plus

(2) the lump-sum equivalent value of the remaining 60 monthly Disability Retirement Payments, calculated as if the person had commenced his or her Incentive Retirement Payments or Mobil Wraparound Payments on the date of death.

7. Beneficiaries

7.1 Designation of Beneficiaries

A person may name one or more designated beneficiaries to receive payment of the benefits payable under this Plan under article 6 above in the event of the person's death. Beneficiary designations shall be made in accordance with such procedures as the Plan Administrator may establish. Spousal consent to any such designation is not required.

7.2 Default Beneficiaries

(A) In General

If no specific designation is in effect, the deceased's beneficiary is the person or persons in the first of the following classes of successive beneficiaries living at the time of death of the deceased:

(1) spouse;

(2) children who survive the deceased or who die before the deceased leaving children of their own who survive the deceased;

(3) parents;

(4) brothers and sisters who survive the deceased or who die before the deceased leaving children of their own who survive the deceased.

If there are no members of any class of such beneficiaries, payment is made to the deceased's executors or administrators.

(B) Allocation Among Default Beneficiaries

If the same class of beneficiaries under paragraph (A) above contains two or more persons, they share equally, with further subdivision of such equal shares as next provided. In class (2), where a child dies before the deceased leaving children who survive the deceased, such child's share is subdivided equally among those children. In class (4), where a brother or sister dies before the deceased leaving children who survive the deceased, such brother or sister's share is subdivided equally among those children.

(C) Definitions

For purposes of this section 7.2, "child" means a person's son or daughter by legitimate blood relationship or legal adoption; "parent" means a person's father or mother by legitimate blood relationship or legal adoption; "brother" or "sister" means another child of either or both of one's parents.

8. Miscellaneous

8.1 Plan Administrator

The Plan Administrator shall be the Manager, Executive Programs, Human Resources Department, Exxon Mobil Corporation. The Plan Administrator shall have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person's eligibility for benefits hereunder.

8.2 Nature of Payments

Payments provided under this Plan are considered general obligations of the Corporation.

8.3 Assignment or Alienation

Except as provided in section 8.5 below, payments provided under this Plan may not be assigned or otherwise alienated or pledged.

8.4 Amendment or Termination

The Corporation reserves the right to amend or terminate this Plan, in whole or in part, including the right at any time to reduce or eliminate any accrued benefits hereunder and to alter or amend the benefit formula set out herein.

8.5 Forfeiture Of Benefits

No person shall be entitled to receive payments under this Plan, and any payments received under this Plan shall be forfeited and returned, if it is determined by the Corporation in its sole discretion, acting through its chief executive or such person or committee as the chief executive may designate, that a person otherwise entitled to a payment under this Plan or who has commenced receiving payments under this Plan:

(A) engaged in gross misconduct harmful to the Corporation,

(B) committed a criminal violation harmful to the Corporation,

(C) had concealed actions described in (A) or (B) above which would have brought about termination from employment thereby making the person ineligible for benefits under this Plan,

(D) terminated employment prior to attaining age 65 without having received from the Corporation or its delegatee prior written approval for such termination, given in the sole discretion of the Corporation or its delegatee and in the context of recognition that benefits under this Plan would not be forfeited upon such termination, or

(E) had been terminated for cause.

KEY EMPLOYEE ADDITIONAL PAYMENTS PLAN

K1. Purpose

This Plan provides additional payments from the general assets of Exxon Mobil Corporation ("Corporation") to certain persons who as of December 31, 1993,

(A) were classified at level 36 or above,

(B) were age 55 and above, and

(C) were eligible to retire with "annuitant status" under the Benefit Plan of Exxon Corporation and Participating Affiliates as it existed on such date.

The amount of these additional payments shall be a function of the person's final average incentive compensation as determined in accordance with this Plan.

K2. Benefits

K2.1 Benefit Formula

Additional payments under this Plan shall be determined by multiplying 1.6% of the person's final average incentive compensation determined under section K2.2 below by the person's years of pensionable service as of December 31, 1993, as determined under the ExxonMobil Pension Plan (or predecessor plan). The amount so derived is an annual benefit which shall be divided by twelve and paid to the person monthly for life with 60 monthly payments guaranteed.

K2.2 Final Average Incentive Compensation

(A) In General

For the purposes of this Plan final average incentive compensation shall be the average of the three highest annual bonus awards to the person under the Corporation's Incentive Programs during the five year period ending on December 31, 1993. In determining the amount of a person's annual bonus award only awards granted under the short-term incentive part of the Incentive Programs as cash, unrestricted shares of stock using the fair market value at the time of award, and bonus units using the maximum settlement value obtainable at the time of grant shall be considered.

(B) One-Time Bonuses

For purposes of paragraph (A) above, an award to a person characterized by the granting authority as a special one-time bonus will be disregarded, unless deemed specifically includable by the granting authority at the time of grant.

K2.3 Non-Forfeitability

A participant in this Plan shall have a non-forfeitable right to the amount of additional payments calculated under this Plan.

K3. Payment of Benefits

K3.1 Commencement of Benefits

(A) In General

Additional payments under this Plan shall be made at the same time as payments under the ExxonMobil Pension Plan commence.

(B) Reduction for Early Commencement

If additional payments commence prior to the month in which the person reaches age 65, they shall be reduced by applying the early commencement factors for retirees set forth in the ExxonMobil Pension Plan for a normal maturity age of 65. For all actuarial purposes, this monthly amount paid as a five-year certain life annuity is deemed the normal form amount.

K3.2 Form of Payment

(A) In General

Additional payments under this Plan, other than payments to designated beneficiaries, are made normally in the form of a five-year certain life annuity, but, in the sole discretion of the Corporation, may be made in any other form, including a joint and survivor form, that is not greater than the actuarial equivalent of the normal form.

(B) Determination of Actuarial Equivalency

For purposes of paragraph (A), actuarial equivalency is determined by the Plan Administrator using factors used for comparable determinations under the ExxonMobil Pension Plan.

K3.3 Offsets

If any person is also entitled to payments of a comparable nature for any portion of the same years of pensionable service under a plan of a service-oriented employer, as defined in the ExxonMobil Common Provisions, other than the Corporation the amount determined immediately above will be reduced by the amount of such comparable payments. In any given case, the Plan Administrator shall determine the precise amount of this offset and if a conversion of currency computation is required, may follow the process established under the ExxonMobil Pension Plan.

K4. Death Benefits

K4.1 Death Benefits

If a person dies, either as an employee or retiree, before commencement of additional payments under this Plan, the person's beneficiary under article K5 below shall receive the lump-sum equivalent value of the additional payments to which the person would have been entitled if he or she had commenced such payments on the date of death.

K4.2 Death During Period Certain

If a person who is receiving additional payments under this Plan for a guaranteed certain period dies before all guaranteed payments have been made, the person's beneficiary under article K5 below shall be entitled to receive the remaining guaranteed payments.

K5. Beneficiaries

K5.1 Designation of Beneficiaries

A person may name one or more designated beneficiaries to receive payment of the benefits payable under this Plan under article K4 above in the event of the person's death. Beneficiary designations shall be made in accordance with such procedures as the Plan Administrator may establish. Spousal consent to any such designation is not required.

K5.2 Default Beneficiaries

(A) In General

If no specific designation is in effect, the deceased's beneficiary will be the person or persons in the first of the following classes of successive beneficiaries living at the time of death of the deceased:

(1) spouse;

(2) children who survive the deceased or who die before the deceased leaving children of their own who survive the deceased;

(3) parents;

(4) brothers and sisters who survive the deceased or who die before the deceased leaving children of their own who survive the deceased.

If there are no members of any class of such beneficiaries, payment is made to the deceased's executors or administrators.

(B) Allocation Among Default Beneficiaries

If the same class of beneficiaries under paragraph (A) above contains two or more persons, they shall share equally, with further subdivision of such equal shares as next provided. In class (2), where a child dies before the deceased leaving children who survive the deceased, such child's share shall be subdivided equally among those children. In class (4), where a brother or sister dies before the deceased leaving children who survive the deceased, such brother or sister's share shall be subdivided equally among those children.

(C) Definitions

For purposes of this section K5.2, "child" means a person's son or daughter by legitimate blood relationship or legal adoption; "parent" means a person's father or mother by legitimate blood relationship or legal adoption; "brother" or "sister" means another child of either or both of one's parents.

K6. Miscellaneous

K6.1 Plan Administrator

The Plan Administrator shall be the Manager, Executive Programs, Human Resources Department, Exxon Mobil Corporation. The Plan Administrator shall have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person's eligibility for benefits hereunder.

K6.2 Nature of Payments

Payments provided under this Plan shall be considered general obligations of the Corporation.

K6.3 Assignment or Alienation

Payments provided under this Plan may not be assigned or otherwise alienated or pledged.

K6.4 Amendment or Termination

The Corporation may at any time amend or terminate this Plan, in whole or in part, so long as the amendment does not deprive any person of the non-forfeitable right to benefits specifically granted in this Plan.

Exhibit 10(iii)(d)

EDITION OF JANUARY 1, 2000

EXXONMOBIL EXECUTIVE LIFE INSURANCE AND DEATH BENEFIT PLAN

Articles

EXXONMOBIL EXECUTIVE LIFE INSURANCE AND

DEATH BENEFIT PLAN

1. Participation

1.1 Covered Executive

Each covered executive is a participant in this Plan.

1.2 Retiree

(A) In General

Except as provided in paragraph (B) below, each person who becomes a retiree on or after the effective date, and who is a covered executive immediately prior to becoming a retiree is a participant in this Plan. In addition, each grandfathered retiree is a participant in the Plan.

(B) Exception

A retiree will cease to be a participant during the time the retiree is a suspended retiree.

1.3 Cessation of Participant Status

(A) Termination of Employment

(1) In General

Except as provided in paragraphs (2) through (4) below, a covered executive will cease to be a participant 31 days after the covered executive terminates employment without becoming a retiree.

(2) Exception for Long Term Disability

A covered executive who terminates employment with eligibility for long-term disability benefits under the ExxonMobil Disability Plan, will cease to be a participant at the earlier of

(a) one year after terminating employment, or

(b) the date the person is no longer eligible for long-term disability benefits on account of ceasing to be disabled.

(3) Exception for Coverage Provided Through Death Benefit

If, at the time a covered executive terminates employment he or she has elected to receive executive life coverage in the form of a death benefit, the covered executive will cease to be a participant on the date of such termination of employment.

(4) Exception for Transition Severance Terminees

(a) In General

A covered executive who terminates employment without becoming a retiree shall continue to be a participant for a period of one year from the date of such termination of employment, but only if the person is eligible for a benefit under the Exxon Transition Severance Plan, or if the Corporation, acting through its management, determines that the covered executive is otherwise eligible for such continued participation.

(b) Termination of Provision

This paragraph (4) shall not apply to any covered executive who terminates employment after August 31, 2000.

(B) Suspended Retirees

A retiree or grandfathered retiree will cease to be a participant during the time the person is a suspended retiree.

2. Coverage

2.1 When and How Coverage is Provided

(A) In General

(1) Executive Life Coverage

Executive life coverage is automatically provided to all participants other than grandfathered retirees.

(2) Supplemental Group Life Coverage

Supplemental group life coverage is automatically provided to all participants who are grandfathered retirees.

(B) Life Insurance or Death Benefit Option

(1) In General

Both executive life coverage and supplemental group life coverage is automatically provided under the Plan as life insurance unless a participant elects to receive coverage in the form of a death benefit.

(2) Election

Participants may, at any time, elect to receive executive life or supplemental group life coverage, whichever is applicable, as a death benefit, and may revoke any such election. An election or revocation under this paragraph (2) shall be made in accordance with procedures established by the administrator.

(3) When Election is Effective

(a) Death Benefit

An election under paragraph (2) above to receive executive life or supplemental group life coverage as a death benefit shall become effective on the first of the month following the receipt of such election by the administrator.

(b) Revocation of Election

A participant's revocation of a death benefit election in favor of receiving executive life or supplemental group life coverage as life insurance becomes effective on the first of the month following the date the administrator receives notification from the insurer that the insurer has, in its discretion, approved evidence of insurability submitted by the participant.

(4) Reinstatement of Coverage

If a participant's executive life or supplemental group life coverage is reinstated after a period in which the participant was ineligible for coverage under section 1.3(B) above on account of becoming a suspended retiree, such coverage shall be reinstated under the option (i.e., life insurance or a death benefit) in force at the time coverage was lost.

(C) Termination of Coverage

Executive life or supplemental group life coverage terminates for an individual on the date the individual ceases to be a participant.

2.2 Amount of Benefit

(A) Executive Life Coverage

(1) In General

Except as provided in paragraph (2) below, the amount of executive life coverage in effect for a participant is equal to the applicable percentage determined under the following chart multiplied by the participant's annual base pay:

If the participant's age is	The percentage is
Under 65	400%
65-69	350%
70-74	300%
75 and over	250%

For this purpose, a participant attains a particular age as of the first day of the month in which the person will turn such age. In addition, a covered executive's annual base pay is the base pay in effect at the time coverage is determined, and a retiree's base pay is the base pay in effect for the person immediately before the person became a retiree.

(2) Transition Severance Terminees

The amount of executive life coverage in effect for a person who is a participant solely on account of section 1.3(A)(4) above relating to transition severance terminees is 200% of the person's annual base pay in effect immediately before the person's termination of employment.

(B) Supplemental Group Life Coverage

Supplemental Group Life Coverage is provided

(1) during retirement to all grandfathered retirees, and

(2) during employment to those persons who become grandfathered retirees after the effective date.

The amount of supplemental group life coverage in effect for a grandfathered retiree is equal to the amount of coverage in effect for the person under the provisions of the Supplemental Group Life Insurance Plan or Supplemental Group Death Benefit Plan (as such plans existed on December 31, 1999) as of the later of December 31, 1999 or the date the person retires. The amount of supplemental group life coverage in effect during employment for a person who becomes a grandfathered retiree after the effective date is the amount of coverage to which they are entitled under the terms of the Supplemental Group Life Insurance Plan or Supplemental Group Death Benefit Plan (as such plans existed on December 31, 1999).

3. Payment of Benefit

3.1 Conditions for Payment of Benefit

If a participant dies while executive life or supplemental group life coverage for that participant is in effect, then the amount of coverage then in effect for the participant becomes payable; provided, that proof of death satisfactory to the insurer must be provided before any benefit becomes payable as life insurance.

3.2 Form of Payment

A benefit payable under Section 3.1 above upon a participant's death shall be paid in a lump sum.

3.3 Source of Payment

(A) Life Insurance

Executive life and supplemental group life coverage in the form of life insurance shall be provided through one or more policies of insurance issued by an insurer selected by the Corporation, and any executive life or supplemental group life benefit payable as insurance shall be paid pursuant to such policy or policies.

(B) Death Benefit

Any executive life or supplemental group life benefit payable as a death benefit shall be paid from the general assets of the Corporation.

3.4 To Whom Paid

A benefit payable under Section 3.1 above upon a participant's death shall be paid as follows:

(A) If a beneficiary designation is in effect at the time of the participant's death, the benefit shall be paid in accordance with such designation.

(B) If no beneficiary designation is in effect, the benefit shall be paid to the first of the following groups that has at least one member that survives the participant:

(1) The participant's spouse.

(2) The participant's children. In this event, the benefit will be divided equally among the children who survive the participant as well as the children who die before the participant leaving children of their own who survive the participant. In the case of a participant's child who dies before the participant leaving children of his or her own

who survive the participant, such child's share shall be divided equally among his or her surviving children.

(3) The participant's parents. In this event, the benefit will be divided equally among the parents if they both survive the participant.

(4) The participant's brothers and sisters. In this event, the benefit will be divided equally among the brothers and sisters who survive the participant as well as the brothers and sisters who die before the participant leaving children of their own who survive the participant. In the case of a brother or sister who dies before the participant leaving children of his or her own who survive the participant, such brother or sister's share shall be divided equally among his or her surviving children.

(5) The participant's executors or administrators.

For purposes of this Paragraph (B), a spouse of a participant shall include only someone who is the legal spouse of the participant, and a child, parent, brother, or sister of a participant shall include only someone who is a legitimate blood relative of the participant or whose relationship with the participant is established by virtue of a legal adoption.

4. Designation of Beneficiary

4.1 Designation

A participant may designate one or more beneficiaries to receive the payment of benefits upon the death of the participant, or may at any time change or cancel a previously made beneficiary designation.

4.2 Forms and Submission

Any beneficiary designation or change or cancellation thereof shall be made on such forms and in such manner as is satisfactory to the insurer. No beneficiary designation or change or cancellation thereof shall become effective until received by the insurer or its designated agent.

4.3 Designation Made Under Prior Plans

Any beneficiary designation made by a participant under the Supplemental Group Life Insurance Plan or Supplemental Death Benefit Plan that remains in effect on December 31, 1999, shall continue to be valid under this Plan on and after the effective date until and unless properly superceded.

5. Miscellaneous

5.1 Plan Funding

The funding for executive life and supplemental group life coverage, including the funding of premiums under any life insurance policy issued in connection with such coverage, shall be paid for by the Corporation; no participant contributions will be required or permitted.

5.2 Assignment of Insurance

(A) Assignment

A participant may assign to another owner the participant's interest in his or her executive life or supplemental group life coverage provided in the form of life insurance. Such assignment shall be made on such forms and in such manner as is acceptable to the administrator and the insurer.

(B) Effect of Assignment

(1) In General

When an assignment of a participant's coverage is in effect as described in paragraph (A) above, then, except as provided in paragraph (2) below, the participant's assignee shall have the right to take all actions under the terms of this Plan with respect to such coverage that the participant would otherwise have the right to take, including, without limitation, the right to designate a beneficiary.

(2) Exception

An assignee shall not have the right under this Plan to elect to receive executive life or supplemental group life coverage as a death benefit under section 2.1(B)(2) above or to revoke an already existing election.

(C) Assignment Under Prior Plan

Any assignment of coverage made by a participant under the Supplemental Group Life Insurance Plan shall continue to be valid under this Plan with respect to executive life and supplemental group life coverage.

5.3 Amendment and Termination

The Corporation at any time, by action of any duly authorized officer, may amend or terminate this Plan in whole or in part.

5.4 Responsibilities and Authority of Administrator

The administrator shall fulfill all duties and responsibilities of a "plan administrator" required by the Employee Retirement Income Security Act of 1974, as amended. The administrator shall have the authority to control and manage the operation and administration of this Plan, including, without limitation:

(A) discretionary and final authority to determine eligibility and to administer this Plan in its application to each participant and beneficiary; and

(B) discretionary and final authority to interpret this Plan, in whole or in part, including but not limited to, exercising such authority in conducting a full and fair review, with such interpretation being conclusive for all participants and beneficiaries under this Plan.

5.5 Claim Appeal Process

(A) Submission of Appeal

In the event a claim for benefits is denied, the claimant has the right to appeal to theadministrator. A written request to review a denied claim must be received by the administrator within 90 days after the claim denial. The request may state the reasons the claimant believes he or she is entitled to Plan benefits, and may be accompanied by supporting information and documentation for the administrator's consideration.

(B) Decision

The administrator shall decide appeals in accordance with theadministrator's fiduciary authority set out in section 5.4 above. Appeal decisions will be made within 60 days of the receipt of the claim by the administrator unless special circumstances warrant an extension of time. If an extension of time is required, the administrator will notify the claimant of the extension. In all cases, the decision will be made no later than 120 days after the receipt of the claim by the administrator. The appeal decision shall be in writing, specify the reasons for the decision, and refer to the relevant Plan provision(s) on which the decision is based.

5.6 Definitions

The following terms shall have the following meanings ascribed to them:

(A) "Administrator" means the Manager, Compensation and Executive Plans, Human Resources Department, Exxon Mobil Corporation.

(B) "Corporation" means Exxon Mobil Corporation.

(C) "Covered Employee" has the meaning set out in the ExxonMobil Benefit Plans Common Provisions.

(D) "Covered Executive" means a covered employee who has a classification level of 35 or higher.

(E) "Effective Date" means January 1, 2000.

(F) "Grandfathered retiree" means a person who

(1) became a retiree prior to the effective date, and was covered under the Supplemental Group Life Insurance Plan or Supplemental Death Benefit Plan immediately prior to the effective date, or who

(2) becomes a retiree after the effective date after having been given the opportunity to elect and having elected continued coverage under the Supplemental Group Life Insurance Plan or Supplemental Death Benefit Plan.

(G) "Insurer" means the insurance company that is the issuer of the policy of insurance described in section 3.3(A) above.

(H) "Participant" means a covered executive, retiree, or grandfathered retiree, as the context requires.

(I) "Retiree"

(1) In General

"Retiree" has the meaning set out in the ExxonMobil Benefit Plans Common Provisions.

(2) Transition Severance Cases

(a) Treatment as Covered Annuitant

Solely for purposes of this Plan, a person who is described in paragraph (b) below shall be treated as if he or she were a retiree.

(b) Eligibility

A person is described in this paragraph (b) if the person

(i) terminates employment as a covered executive;

(ii) is at least 50 years old by the end of the month in which the termination of employment occurs;

(iii) has at least 10 years of benefit plan service (as defined in the ExxonMobil Benefit Plans Common Provisions) at the time of the termination of employment; and

(iv) upon termination of employment receives a benefit under the Exxon Transition Severance Plan.

(c) Termination of Provision

This paragraph (2) shall not apply to any person who fails to meet the eligibility requirements set out in paragraph (b) above on or before August 31, 2000.

(J) "Suspended retiree"

(1) In General

"Suspended Retiree" means a person who becomes a retiree by virtue of being incapacitated within the meaning of the ExxonMobil Disability Plan and commences long-term disability benefits under such Plan, but whose benefits under such Plan thereafter cease by virtue of

(a) the person no longer being incapacitated, or

(b) the person's failure to report non-rehabilitative employment.

(2) Period

A person remains a suspended retiree until the earlier of (1) the date the person attains age 55, or (2) the date the person commences his or her benefit or receives a lump-sum settlement under the ExxonMobil Pension Plan, at which time the person is again considered a retiree.

Exhibit 10(iii)(f.1)

Resolution Adopted by the Board of Directors
Regarding Cash Compensation of Non-employee Directors

September 27, 2000

RESOLVED, that, effective October 1, 2000, each member of the Board of Directors who is not an employee of the Corporation or of any of its affiliated companies (a "non-employee director") be compensated at the rate of $75,000 per annum, and that in addition,

(a) each non-employee director be compensated at the rate of $15,000 per annum for each membership held on the Board Audit Committee or the Board Compensation Committee and at the rate of $8,000 per annum for each membership held on any other committee established by the Board of Directors or by the Executive Committee, except for the Executive Committee itself; and

(b) each non-employee director designated as Chairman of the Board Audit Committee or the Board Compensation Committee be compensated at the rate of $10,000 per annum and each non-employee director designated as Chairman of any other committee of the Board, except the Executive Committee, be compensated at the rate of $7,000 per annum; and

(c) non-employee directors receive no additional fees for attendance at regular or special meetings of the Board or any committee of the Board, or for execution of written consents to action in lieu of meetings of the Board or any such committee, but be reimbursed for reasonable expenses if any; and that the resolutions regarding non-employee director remuneration adopted by the Board of Directors on January 25, 1995 be, and hereby are, revoked.

STOCK OPTION TERMS AND CONDITIONS
February 26, 1999 Grant

TERM OF THE OPTION

The February 26, 1999 stock option grant for the purchase of Mobil Corporation Common Stock will become fully exercisable beginning February 26, 2002 when you have completed three years of Mobil service after the grant date. The options have a 10-year term and will expire at 4:30 p.m. (Eastern Standard Time) on February 25, 2009 (or earlier, as provided in section 6.8 or 6.9 of the 1995 Mobil Incentive Compensation and Stock Ownership Plan referred to as the "Plan"). You are urged to make note of these dates since no further communication will be provided to you when these options become exercisable or expire.

TRANSFERABILITY

The options covered by this grant are not transferable other than by will or the laws of descent and distribution and may be exercised during your lifetime only by you.

SPECIAL PROVISIONS

If you die while you are an employee, any rights you had immediately prior to your death to exercise the options granted to you hereunder during its remaining term shall pass to the person(s) designated in your will or determined by the laws of intestacy. In addition, any of your options that were not exercisable shall be immediately exercisable for the remaining term.

If your employment terminates for any reason other than death before the options granted to you hereunder become fully exercisable, the Board Compensation Committee may, in its absolute discretion, determine (but shall be under no obligation to determine) that the three-year service requirement of such options may be waived so as to avoid forfeiture and make the options immediately exercisable in whole or in part. Any exercise in such situations is subject to the provisions of Plan sections 6.8 and 6.9. Employees must generally complete the full calendar year in which the option was granted before waiver of the service requirement will be considered by the Committee.

CONDITIONS

The stock option grant is subject to the terms and conditions specified in the Plan, which is incorporated by reference as part of the Award Notification and the Stock Option Terms and Conditions.

TAX MATTERS

Below is general information regarding the tax treatment of options. Additional information is available through the "ICP icon," if you are on Lotus Notes mail.

US Executives

Under current federal tax law, you have no tax liability on account of your stock option grant. However, your tax liability at exercise depends upon the type of option granted to you. The portion of your option grant designated as ISOs are not subject to regular tax upon exercise. Mobil therefore withholds no taxes from your ISO exercises. You will generally recognize taxable income when you sell your ISO shares. NQSOs, on the other hand, are subject to tax upon exercise, and Mobil is required to immediately collect applicable payroll taxes (federal and state income taxes and FICA).

Executives on Non-US Payroll

Due to the different tax laws in each country, you are strongly encouraged to consult with your tax advisor regarding the tax consequences of your stock option grant, the exercise of your options, and the sale of your option stock. If you are working outside your home country at the time of exercise, a "hypothetical" home country tax will be collected at the time of exercise, in accordance with applicable Mobil policy.

EXHIBIT 12

EXXON MOBIL CORPORATION

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
			(millions of dollars)		
Income from continuing operations	$25,330	$20,960	$11,011	$15,003	$15,806
Excess/(shortfall) of dividends over earnings of affiliates owned less than 50 percent accounted for by the equity method	(475)	(205)	(140)	(108)	(354)
Provision for income taxes(1)	16,644	11,734	7,073	9,599	11,614
Capitalized interest	(180)	(180)	(143)	(255)	(409)
Minority interests in earnings of consolidated subsidiaries	773	692	206	556	346
	42,092	33,001	18,007	24,795	27,003
Fixed Charges:(1)					
Interest expense—borrowings	182	182	368	328	637
Capitalized interest	515	497	442	529	653
Rental expense representative of interest factor	498	424	587	621	551
Dividends on preferred stock	5	3	5	8	12
	1,200	1,106	1,402	1,486	1,853
Total adjusted earnings available for payment of fixed charges	$43,292	$34,107	$19,409	$26,281	$28,856
Number of times fixed charges are earned	36.1	30.8	13.8	17.7	15.6

Note:

(1) The provision for income taxes and the fixed charges include Exxon Mobil Corporation's share of 50 percent-owned companies and majority-owned subsidiaries that are not consolidated.

EXHIBIT 21

Subsidiaries of the Registrant (1), (2) and (3)

AT DECEMBER 31, 2004

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Abu Dhabi Petroleum Company Limited (5)	23.75	England
Aera Energy LLC (5)	48.2	California
Al-Jubail Petrochemical Company (4) (5)	50	Saudi Arabia
Ampolex (CEPU) Pte Ltd	100	Singapore
Ancon Insurance Company, Inc.	100	Vermont
BEB Erdgas und Erdoel GmbH (4) (5)	50	Germany
Cameroon Oil Transportation Company S.A. (5)	41.07	Cameroon
Caspian Pipeline Consortium (5)	7.5	Russia/Kazakhstan
Castle Peak Power Company Limited (5)	60	Hong Kong
Chalmette Refining, LLC (4) (5)	50	Delaware
Esso Australia Resources Pty Ltd	100	Australia
Esso Austria GmbH	100	Austria
Esso Brasileira de Petroleo Limitada	100	Brazil
Esso Chile Petrolera Limitada	100	Chile
Esso Deutschland GmbH	100	Germany
Esso Erdgas Beteiligungsgesellschaft mbH	100	Germany
Esso Espanola, S.L.	100	Spain
Esso Exploration and Production Angola (Block 31) Limited	100	Bahamas
Esso Exploration and Production Chad Inc.	100	Delaware
Esso Exploration and Production Nigeria (Deepwater) Limited	100	Nigeria
Esso Exploration and Production Nigeria Limited	100	Nigeria
Esso Exploration and Production UK Limited	100	England
Esso Exploration Angola (Block 15) Limited	100	Bahamas
Esso Exploration Angola (Block 17) Limited	100	Bahamas
Esso Ireland Limited	100	Ireland
Esso Italiana S.r.l.	100	Italy
Esso Malaysia Berhad	65	Malaysia
Esso Natuna Ltd.	100	Bahamas
Esso Nederland B.V.	100	Netherlands
Esso Norge AS	100	Norway
Esso Petrolera Argentina Sociedad de Responsabilidad Limitada	100	Argentina
Esso Petroleum Company, Limited	100	England
Esso Pipeline Investments Limited	100	Bahamas
Esso Raffinage S.A.F.	82.89	France
Esso Schweiz GmbH	100	Switzerland
Esso Societe Anonyme Francaise	82.89	France
Esso (Thailand) Public Company Limited	87.5	Thailand
Esso Trading Company of Abu Dhabi	100	Delaware
Exxon Azerbaijan Caspian Sea Limited	100	Bahamas
Exxon Azerbaijan Limited	100	Bahamas
Exxon Capital Corporation	100	New Jersey
Exxon Chemical Arabia Inc.	100	Delaware
Exxon Chemical Asset Management Partnership	93.2	Delaware

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Exxon Luxembourg Holdings LLC	100	Delaware
Exxon Mobile Bay Limited Partnership	94.47	Delaware
Exxon Neftegas Limited	100	Bahamas
Exxon Overseas Corporation	100	Delaware
Exxon Yemen Inc.	100	Delaware
ExxonMobil Alaska Production Inc.	100	Delaware
ExxonMobil Asia Pacific Pte. Ltd.	100	Singapore
ExxonMobil Aviation International Limited	100	England
ExxonMobil Canada Ltd.	100	Canada
ExxonMobil Capital N.V.	100	Netherlands
ExxonMobil Central Europe Holding GmbH	100	Germany
ExxonMobil Chemical Central Europe GmbH	100	Germany
ExxonMobil Chemical Films Europe, Inc.	100	Delaware
ExxonMobil Chemical France S.A.R.L.	99.77	France
ExxonMobil Chemical Holland B.V.	100	Netherlands
ExxonMobil Chemical Limited	100	England
ExxonMobil Chemical Operations Private Limited	100	Singapore
ExxonMobil Chemical Polymeres SNC	99.77	France
ExxonMobil de Colombia S.A.	99.42	Colombia
ExxonMobil Egypt (S.A.E.)	100	Egypt
ExxonMobil Energy Limited	100	Hong Kong
ExxonMobil Exploration and Production Malaysia Inc.	100	Delaware
ExxonMobil Exploration and Production Norway AS	100	Norway
ExxonMobil Far East Holdings Ltd.	100	Bahamas
ExxonMobil Gas Marketing Deutschland GmbH	99.999	Germany
ExxonMobil Gas Marketing Europe Limited	100	England
ExxonMobil Global Services Company	100	Delaware
ExxonMobil Holding Company Holland LLC	100	Delaware
ExxonMobil Hong Kong Limited	100	Hong Kong
ExxonMobil International Holdings Inc.	100	Delaware
ExxonMobil International Services, SARL	100	Luxembourg
ExxonMobil Kazakhstan Inc.	100	Bahamas
ExxonMobil Kazakhstan Ventures Inc.	100	Delaware
ExxonMobil Luxembourg UK, SARL	100	Luxembourg
ExxonMobil Malaysia Sdn Bhd	100	Malaysia
ExxonMobil Marine Limited	100	England
ExxonMobil Middle East Gas Marketing Limited	100	Bahamas
ExxonMobil Oil Corporation	100	New York
ExxonMobil Oil Indonesia Inc.	100	Delaware
ExxonMobil Petroleum & Chemical	100	Belgium
ExxonMobil Pipeline Company	100	Delaware
ExxonMobil Production Deutschland GmbH	100	Germany
ExxonMobil Production Norway Inc.	100	Delaware

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
ExxonMobil Qatargas Inc.	100	Delaware
ExxonMobil Rasgas Inc.	100	Delaware
ExxonMobil Sales and Supply Corporation	100	Delaware
ExxonMobil Southwest Holdings Inc.	100	Delaware
ExxonMobil Yugen Kaisha	100	Japan
Fina Antwerp Olefins N.V. (5)	35	Belgium
Imperial Oil Limited	69.6	Canada
Infineum Holdings B.V. (5)	49.96	Netherlands
Kyokuto Sekiyu Kogyo Kabushiki Kaisha (4) (5)	50	Japan
Mineraloelraffinerie Oberrhein GmbH & Co. KG (5)	25	Germany
Mobil Argentina S.A.	100	Argentina
Mobil Australia Resources Company Pty Limited	100	Australia
Mobil California Exploration & Producing Asset Company	100	Delaware
Mobil Caspian Pipeline Company	100	Delaware
Mobil Cerro Negro, Ltd.	100	Bahamas
Mobil Corporation	100	Delaware
Mobil Equatorial Guinea Inc.	100	Delaware
Mobil Erdgas-Erdoel GmbH	99.999	Germany
Mobil Exploration Indonesia Inc.	100	Delaware
Mobil Fairfax Inc.	100	Delaware
Mobil North Sea Limited	100	Delaware
Mobil Oil Australia Pty Ltd	100	Australia
Mobil Oil Exploration & Producing Southeast Inc.	100	Delaware
Mobil Oil New Zealand Limited	100	New Zealand
Mobil Pipe Line Company	100	Delaware
Mobil Producing Nigeria Unlimited	100	Nigeria
Mobil Producing Texas & New Mexico Inc.	100	Delaware
Mobil Refining Australia Pty Ltd	100	Australia
Mobil Yanbu Petrochemical Company Inc.	100	Delaware
Mobil Yanbu Refining Company Inc.	100	Delaware
Nansei Sekiyu Kabushiki Kaisha (6)	43.77	Japan
Nederlandse Aardolie Maatschappij B.V. (4) (5)	50	Netherlands
Paxon Polymer Company, L.P. II	92.84	Delaware
Qatar Liquefied Gas Company Limited (5)	10	Qatar
QM Tanker Co., LLC (4)	50	Cayman Island
Ras Laffan Liquefied Natural Gas Company Limited (5)	26.5	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (II) (5)	29.999	Qatar
Samoco LLC (4)	50	Cayman Island
Saudi Aramco Mobil Refinery Company Ltd. (4) (5)	50	Saudi Arabia
Saudi Yanbu Petrochemical Co. (4) (5)	50	Saudi Arabia
SeaRiver Maritime Financial Holdings, Inc.	100	Delaware
SeaRiver Maritime, Inc.	100	Delaware
Societa per Azioni Raffineria Padana Olii Minerali - SARPOM	74.14	Italy

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Superior Oil (U.K.) Limited	100	England
Tengizchevroil, LLP (5)	25	Kazakhstan
TonenGeneral Sekiyu K.K.	50.021	Japan
Tonen Kagaku K.K.	50.021	Japan

NOTES:

(1) For the purposes of this list, if the registrant owns directly or indirectly approximately 50 percent of the voting securities of any person and approximately 50 percent of the voting securities of such person is owned directly or indirectly by another interest, or if the registrant includes its share of net income of any other unconsolidated person in consolidated net income, such person is deemed to be a subsidiary.

(2) With respect to certain companies, shares in names of nominees and qualifying shares in names of directors are included in the above percentages.

(3) The names of other subsidiaries have been omitted from the above list since considered in the aggregate, they would not constitute a significant subsidiary under Securities and Exchange Commission Regulation S-X, Rule 1-02(w).

(4) The registrant owns directly or indirectly approximately 50 percent of the securities of this person and approximately 50 percent of the voting securities of this person is owned directly or indirectly by another single interest.

(5) The investment in this unconsolidated person is represented by the registrant's percentage interest in the underlying net assets of such person. The accounting for these unconsolidated persons is referred to as the equity method of accounting.

(6) The percentage interest shown reflects an 87.5% ownership of voting securities by TonenGeneral Sekiyu K.K., of which the registrant owns 50.021% of voting securities.

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the following Registration Statements on:

Form S-3	(No. 33-48919)	—	Guaranteed Debt Securities and Warrants to Purchase Guaranteed Debt Securities of Exxon Capital Corporation;
Form S-3	(No. 33-8922)	—	Guaranteed Debt Securities of SeaRiver Maritime Financial Holdings, Inc. (formerly Exxon Shipping Company);
Form S-8	(Nos. 333-101175, 333-38917 and 33-51107)	—	1993 Incentive Program of Exxon Mobil Corporation;
Form S-8	(No. 333-110494)	—	2003 Incentive Program of Exxon Mobil Corporation;
Form S-8	(No. 333-69378)	—	ExxonMobil Fuels Marketing Savings Plan;
Form S-8	(No. 333-72955)	—	ExxonMobil Savings Plan;
Form S-8	(No. 333-75659)	—	Post-Effective Amendment No. 2 on Form S-8 to Form S-4 which pertains to the 1993 Incentive Program of Exxon Mobil Corporation;
Form S-8	(No. 333-117980)	—	2004 Non-employee Director Restricted Stock Plan

of our report dated February 28, 2005, relating to the financial statements, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/S/ PRICEWATERHOUSECOOPERS LLP

Dallas, Texas
February 28, 2005

EXHIBIT 31.1

Certification by Lee R. Raymond
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Lee R. Raymond, certify that:

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

Date: February 28, 2005

/s/ LEE R. RAYMOND

Lee R. Raymond
Chief Executive Officer

EXHIBIT 31.2

Certification by Patrick T. Mulva
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Patrick T. Mulva, certify that:

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

Date: February 28, 2005

/s/ PATRICK T. MULVA

Patrick T. Mulva
Vice President and Controller
(Principal Accounting Officer)

EXHIBIT 31.3

Certification by Donald D. Humphreys
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Donald D. Humphreys, certify that:

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

Date: February 28, 2005

/s/ DONALD D. HUMPHREYS

Donald D. Humphreys
Vice President and Treasurer
(Principal Financial Officer)

EXHIBIT 32.1

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Lee R. Raymond, the chief executive officer of Exxon Mobil Corporation (the "Company"), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2004, as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: February 28, 2005

/s/ LEE R. RAYMOND

Lee R. Raymond
Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Patrick T. Mulva, the principal accounting officer of Exxon Mobil Corporation (the “Company”), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2004, as filed with the Securities and Exchange Commission on the date hereof (the “Report”) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: February 28, 2005

/s/ PATRICK T. MULVA

Patrick T. Mulva
Vice President and Controller
(Principal Accounting Officer)

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.3

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Donald D. Humphreys, the principal financial officer of Exxon Mobil Corporation (the "Company"), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2004, as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: February 28, 2005

/s/ DONALD H. HUMPHREYS

Donald H. Humphreys
Vice President and Treasurer
(Principal Financial Officer)

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to the Securities and Exchange Commission or its staff upon request.