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2005

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, 2005
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 (State or other jurisdiction of incorporation or organization)	13-5409005 (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 (6,106,332,510 shares outstanding at January 31, 2006)	**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**

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ___ No ü

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 ü 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. ü

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ü Accelerated filer ___ Non-accelerated filer ___

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

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2005, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $57.47 on the New York Stock Exchange composite tape, was in excess of $362 billion.

Documents Incorporated by Reference:
Proxy Statement for the 2006 Annual Meeting of Shareholders (Part III)

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EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2005

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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 commodity 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 as well as projects to reduce nitrogen oxide and sulfur oxide emissions. ExxonMobil's 2005 worldwide environmental costs for all such preventative and remediation steps were about $3.3 billion, of which $1.2 billion were capital expenditures and $2.1 billion were included in expenses. The total cost for such activities is expected to remain in this range in 2006 and 2007 (with capital expenditures approximately 35 percent of the total).

Operating data and industry segment information for the Corporation are contained on pages 30, 73, 74 and 86; information on oil and gas reserves is contained on pages 80 through 83 and information on Company-sponsored research and development activities is contained on page 58 of the Financial Section of this report.

The number of regular employees was 83.7 thousand, 85.9 thousand and 88.3 thousand at years ended 2005, 2004 and 2003, 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 22.4 thousand, 19.3 thousand and 17.4 thousand at years ended 2005, 2004 and 2003, 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.

Item 1A. ***Risk Factors*.**

ExxonMobil’s financial and operating results are subject to a number of factors, many of which are not within the company’s control. These factors include the following:

Industry and Economic Factors: The oil and gas business is fundamentally a commodity business. This means the operations and earnings of the Corporation and its affiliates throughout the world may be significantly affected by changes in oil, gas and petrochemical prices and by changes in margins on gasoline and other refined products. Oil, gas, petrochemical and product prices and margins in turn depend on local, regional and global events or conditions that affect supply and demand for the relevant commodity. 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 regional energy demand (such as the demand for heating oil or gas in winter) as well as severe weather events (such as hurricanes) that can disrupt supplies or interrupt the operation of ExxonMobil facilities;
- 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.

Under certain market conditions, factors that have a positive impact on one segment of our business may have a negative impact on another segment and vice versa.

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 both industrial and individual consumers. The Corporation competes with other firms in the sale or purchase of needed goods and 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 businesses, is ExxonMobil’s ability to manage expenses successfully. This requires continuous management focus on reducing unit costs and improving efficiency including through technology improvements, cost control, productivity enhancements and regular reappraisal of our asset portfolio as described elsewhere in this report.

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 factors including:

- political instability or lack of well-established and reliable legal systems in areas where the Corporation operates;
- other political developments and laws and regulations (such as expropriation or forced divestiture of assets and unilateral cancellation or modification of contract terms, as well as de-regulation of certain energy markets);
- environmental regulations;

- restrictions on exploration, production, imports and exports;
- restrictions on the Corporation's ability to do business with certain countries, or to engage in certain areas of business within a country;
- price controls;
- tax or royalty increases (including retroactive claims);
- war or other international conflicts; and
- civil unrest.

Both the likelihood of these occurrences and their overall effect upon the Corporation vary greatly from country to country and are not predictable. A key component of the Corporation's strategy for managing political risk is geographic diversification of the Corporation's assets and operations.

Project Factors: In addition to some of the factors cited above, ExxonMobil's results depend upon the Corporation's ability to develop and operate major projects and facilities as planned. The Corporation's results will therefore be affected by events or conditions that impact the advancement, operation, cost or results of such projects or facilities, including:

- the outcome of negotiations with co-venturers, governments, suppliers, customers or others (including, for example, our ability to negotiate favorable long-term contracts with customers, or the development of reliable spot markets, that may be necessary to support the development of particular production projects);
- reservoir performance and natural field decline;
- changes in operating conditions and costs, including costs of third party equipment or services such as drilling rigs and shipping;
- security concerns or acts of terrorism that threaten or disrupt the safe operation of company facilities; and
- the occurrence of unforeseen technical difficulties (including technical problems that may delay start-up or interrupt production from an Upstream project or that may lead to unexpected downtime of refineries or petrochemical plants).

See section 1 of Item 2 of this report for a discussion of additional factors affecting future capacity growth and the timing and ultimate recovery of reserves.

Market Risk Factors: See pages 40 and 41 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.

Item 1B. ***Unresolved Staff Comments.***

None.

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 8, which note appears on page 60, and on pages 76 through 85.

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 2005

Estimated proved reserves are shown on pages 80 through 83 of the Financial Section of this report. No major discovery or other favorable or adverse event has occurred since December 31, 2005, that would cause a significant change in the estimated proved reserves as of that date. For information on the standardized measure of discounted future net cash flows relating to proved oil and gas reserves, see pages 84 and 85 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 80 through 83 of the Financial Section of this report for the year ended December 31, 2005. The Corporation has reported 2004 and 2005 proved reserves on the basis of December 31 prices and costs. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

	United States	Canada	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	South America	Total Consolidated
					(millions of barrels)			
Liquids	2,113	832	883	2,312	515	707	451	7,813
					(billions of cubic feet)			
Natural gas	13,692	1,705	8,398	841	7,279	821	619	33,355
					(millions of oil-equivalent barrels)			
Oil-equivalent basis	4,395	1,116	2,283	2,452	1,728	844	554	13,372

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

	Year-End 2005		Year-End 2004	
	Developed	Undeveloped	Developed	Undeveloped
		(millions of oil-equivalent barrels)		
Consolidated Subsidiaries				
United States	3,411	984	3,726	922
Canada	862	254	836	105
Europe	1,711	572	1,942	603
Africa	1,281	1,171	1,164	1,408
Asia Pacific/Middle East	1,475	253	1,143	437
Russia/Caspian	93	751	34	776
South America	279	275	176	430
Total	9,112	4,260	9,021	4,681
Equity Companies				
United States	345	91	367	59
Europe	1,713	468	1,649	627
Asia Pacific/Middle East	1,938	2,629	1,404	2,007
Russia/Caspian	713	373	740	399
Total	4,709	3,561	4,160	3,092

In the preceding reserves information, and in the reserves tables on pages 80 through 83 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 to grow over the period 2006-2010. However, actual volumes will vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, asset sales, severe weather events, price effects on production sharing contracts and other factors as described in Item 1A—Risk Factors 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, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressure declines. 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 2005, 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 2004, 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 and gas reserves reported on EIA-23 and those reported in the registrant's Annual Report on Form 10-K for 2004 exceeds five percent.

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

Reference is made to pages 76 and 77 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 81 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 82 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.

4. Gross and Net Productive Wells

	Year-End 2005				Year-End 2004			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States	28,288	10,865	9,187	5,441	30,702	11,949	9,335	5,577
Canada	5,967	5,214	6,115	2,991	7,156	5,890	5,663	2,752
Europe	1,872	590	1,294	512	1,872	594	1,304	520
Africa	674	277	14	6	562	235	18	7
Asia Pacific/Middle East	1,991	532	259	180	2,078	577	235	172
Russia/Caspian	77	16	2	1	63	13	—	—
South America	154	64	89	30	177	65	67	25
Total	39,023	17,558	16,960	9,161	42,610	19,323	16,622	9,053

The numbers of wells operated at year-end 2005 were 17,351 gross wells and 14,028 net wells. At year-end 2004, the numbers of operated wells were 18,427 gross wells and 15,216 net wells.

5. Gross and Net Developed Acreage

	Year-End 2005		Year-End 2004	
	Gross	Net	Gross	Net
	(thousands of acres)			
United States	9,194	5,260	9,017	5,480
Canada	5,615	2,238	5,535	2,499
Europe	11,303	4,687	11,345	4,715
Africa	1,497	545	1,179	475
Asia Pacific/Middle East	7,876	1,570	10,116	2,436
Russia/Caspian	531	116	487	103
South America	690	232	1,331	388
Total	36,706	14,648	39,010	16,096

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 2005		Year-End 2004	
	Gross	Net	Gross	Net
	(thousands of acres)			
United States	10,388	6,413	10,913	7,055
Canada	10,070	4,822	10,440	5,997
Europe	8,782	2,778	8,418	2,245
Africa	49,328	29,048	41,380	21,797
Asia Pacific/Middle East	7,114	3,797	7,806	4,180
Russia/Caspian	2,561	569	2,605	561
South America	26,552	19,513	27,020	19,688
Total	114,795	66,940	108,582	61,523

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 from property to property. 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, many of the early licenses issued under the first four licensing rounds, provided for an initial term of six years with relinquishment of at least one-half of the original area at the end of the initial term, subject to extension for a further 40 years. ExxonMobil's licenses issued in 2005 as part of the 23rd licensing round have an initial term of four years with a second term extension of four years and final term of 18 years. There is a mandatory relinquishment of 50-percent of acreage after the initial term and of all acreage that is not covered by a development plan at the end of the second term.

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.

ASIA PACIFIC / MIDDLE EAST

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, depending on whether deep water areas or otherwise, 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 (an additional extension of three years is possible in certain circumstances). 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.

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. The Government of Yemen awarded a five-year extension of the Marib PSA, but later repudiated the extension and expelled the concession holders. The parties are now in arbitration over the validity of the extension.

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.

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.

RUSSIA/CASPIAN

Azerbaijan

The production sharing agreement (PSA) for the development of the Azeri-Chirag-Gunashli field 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.

Russia

Terms for ExxonMobil's acreage are fixed by the production sharing agreement (PSA) that became effective in 1996 between the Russian government and the Sakhalin-1 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.

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 Association Agreements containing risk/profit provisions negotiated with the national oil company or its affiliates. Association Agreements are awarded for a term not to exceed 39 years. These agreements have an exploration and a production phase. The term of production begins after the exploration phase and runs for 20 years with the possibility of an extension, so long as the total contract term does not exceed 39 years.

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.

8. Number of Net Productive and Dry Wells Drilled

	2005	2004	2003
A. Net Productive Exploratory Wells Drilled			
United States	13	11	13
Canada	1	2	13
Europe	4	3	4
Africa	5	2	4
Asia Pacific/Middle East	1	2	2
Russia/Caspian	—	1	—
South America	—	—	2
Total	24	21	38
B. Net Dry Exploratory Wells Drilled			
United States	5	6	10
Canada	—	4	9
Europe	1	1	3
Africa	5	4	3
Asia Pacific/Middle East	1	—	3
Russia/Caspian	1	—	—
South America	—	—	—
Total	13	15	28
C. Net Productive Development Wells Drilled			
United States	537	568	598
Canada	263	466	297
Europe	19	24	36
Africa	61	64	59
Asia Pacific/Middle East	50	35	68
Russia/Caspian	7	4	2
South America	9	3	—
Total	946	1,164	1,060
D. Net Dry Development Wells Drilled			
United States	8	13	14
Canada	2	2	16
Europe	2	2	2
Africa	—	—	1
Asia Pacific/Middle East	2	1	1
Russia/Caspian	—	—	—
South America	—	—	—
Total	14	18	34
Total number of net wells drilled	997	1,218	1,160

9. Present Activities

A. Wells Drilling

	Year-End 2005		Year-End 2004	
	Gross	Net	Gross	Net
United States	148	84	179	81
Canada	148	94	31	17
Europe	46	12	32	8
Africa	53	21	80	33
Asia Pacific/Middle East	70	24	52	25
Russia/Caspian	38	8	31	5
South America	3	1	3	1
Total	506	244	408	170

B. Review of Principal Ongoing Activities in Key Areas

During 2005, 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 2005. At year-end 2005, ExxonMobil's acreage totaled 11.7 million net acres, of which 3.0 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska.

During 2005, 514.3 net exploration and development wells were completed in the inland lower 48 states and 9.0 net development wells were completed offshore in the Pacific. An acid gas injection project was started up to increase existing plant capacity at the Shute Creek treating facility in La Barge, Wyoming, and tight gas development continues in the Piceance Basin of Colorado. Participation in Alaska production and development continued and a total of 23.7 net exploration and 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 engineering design for facility expansions.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2005 was 2.8 million acres. A total of 16.2 net exploration and development wells were completed during the year. Installation of the semi-submersible production and drilling vessel, along with infrastructure to transport future oil and gas production onshore, continued for the Thunder Horse development in 2005. Startup, delayed due to a listing incident, is anticipated to occur in 2006.

CANADA

ExxonMobil's year-end 2005 acreage holdings totaled 7.1 million net acres, of which 3.1 million net acres were offshore. A total of 266.7 net exploration and development wells were completed during the year. In eastern Canada, work continued on the Sable Compression project.

EUROPE

France

ExxonMobil's acreage at year-end 2005 was 0.1 million net onshore acres.

Germany

A total of 2.3 million net onshore acres and 0.1 million net offshore acres were held by ExxonMobil at year-end 2005, with 7.6 net exploration and development wells drilled during the year.

Netherlands

ExxonMobil's interest in licenses totaled 1.9 million net acres at year-end 2005, 1.5 million acres onshore and 0.4 million acres offshore. During 2005, 1.8 net exploration and development wells were drilled. Offshore, the first unmanned minimum facility monotower platform was successfully located on the K17-FA field. 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 2005 totaled approximately 1.0 million acres, all offshore. ExxonMobil participated in 7.7 net exploration and development well completions in 2005. Production was initiated at the Oseberg J field in June, the Aasgard Q field in August and the Kristin field in November 2005. The Sleipner A low pressure project and Ringhorne East, Oseberg Vestflanken, Fram East and Ormen Lange field developments are in progress.

United Kingdom

ExxonMobil's net interest in licenses at year-end 2005 totaled approximately 2.1 million acres, all offshore. A total of 9.4 net exploration and development wells were completed during the year. The Arthur project commenced production in early 2005. Other projects progressed in 2005 include Caravel, Cutter, Merganser and Starling.

AFRICA

Angola

ExxonMobil's year-end 2005 acreage holdings totaled 0.7 million net offshore acres and 12.0 net exploration and development wells were completed during the year. On Block 15, production began in July from the Kizomba B development and design work is complete on the Marimba development, which will tie-back to the Kizomba A Floating, Production, Storage and Offloading (FPSO) vessel. Planning for the Kizomba C development is ongoing. A block-wide 4D seismic acquisition program started late in the year. On Block 17, construction is underway on the Dalia and Rosa developments.

Cameroon

ExxonMobil's acreage totaled 0.3 million net offshore acres at year-end 2005.

Chad

ExxonMobil's net year-end 2005 acreage holdings consisted of 3.3 million onshore acres, with 35.6 net exploration and development wells completed during the year. Development of the Moundouli field is in progress.

Equatorial Guinea

ExxonMobil's acreage totaled 0.4 million net offshore acres at year-end 2005, with 4.5 net development wells completed during the year.

Nigeria

ExxonMobil's net acreage totaled 1.6 million offshore acres at year-end 2005, with 17.3 net exploration and development wells completed during the year. The ExxonMobil-operated Yoho field (OML 104) early production system was expanded, and the full field production platform was installed. The ExxonMobil-operated East Area Additional Oil Recovery platform was also installed, and detailed design and construction began on the ExxonMobil-operated East Area NGL II project. Production began in 2005 at the deepwater Bonga field (OML 118). Drilling continued at the ExxonMobil-operated deepwater Erha field (OPL 209), and the Erha FPSO vessel arrived. Construction continued on the

Amenam-Kpono Phase 2 Gas project and Front End Engineering and Design (FEED) work was initiated on the deepwater Usan field (OPL 222).

ASIA PACIFIC / MIDDLE EAST

Australia

ExxonMobil's net year-end 2005 acreage holdings totaled 1.2 million acres, all offshore. ExxonMobil drilled a total of 11.4 net exploration and development wells in 2005.

Indonesia

ExxonMobil had acreage of 2.5 million net acres at year-end 2005, 1.7 million acres offshore and 0.8 million acres onshore.

The production sharing contract for the Cepu Contract Area was signed in September 2005 by PT Pertamina (Persero) and ExxonMobil and approved by the Government of Indonesia. The term of the contract is 30 years. PT Pertamina (Persero) and ExxonMobil are currently working on the Joint Operation Agreement (JOA).

Japan

ExxonMobil's net offshore acreage was 36 thousand acres at year-end 2005.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.5 million net acres offshore Malaysia at year-end 2005. During the year, a total of 25.6 net development wells were completed. Development and infill drilling wells were successfully completed at six platforms: Guntong-F, Irong Barat-C, Tapis-C, Semangkok-B, Angsi-A and Tiong-A. First oil was produced from the Guntong-F and Irong Barat-C platforms in 2005. Drilling activities are currently ongoing at Jerneh-A.

Papua New Guinea

A total of 0.5 million net onshore acres were held by ExxonMobil at year-end 2005, with 0.6 net development wells completed during the year.

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 I)
Qatar Liquefied Gas Company Limited (II) — (QG II)
Ras Laffan Liquefied Natural Gas Company Limited — (RL I)
Ras Laffan Liquefied Natural Gas Company Limited (II) — (RL II)
Ras Laffan Liquefied Natural Gas Company Limited (3) — (RL 3)

In addition, production commenced in 2005 for ExxonMobil's Al Khaleej Gas (AKG) project which supplies pipeline gas to domestic industrial customers. The AKG project will have a target peak production rate of 675 million of cubic feet per day (gross) and produce associated condensate, and commencing in early 2006 will produce LPG (Liquefied Petroleum Gas).

At the end of 2005, 54 (gross) wells supplied natural gas to currently producing LNG and pipeline gas sales facilities and drilling is underway to complete wells that will supply the new QG II, RL II and RL 3 projects. A total of 9.1 net exploration and development wells were completed in 2005.

Qatar LNG capacity volumes at year-end included 9.7 MTA (millions of metric tons per annum) in QG I Trains 1-3 and a combined 16.0 MTA in RL I Trains 1-2 and RL II Trains 3-4. During 2005, production commenced at RL II Train 4, and an expansion project was completed to increase the capacity of QG I 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 Train 5 and RL 3 Trains 6-7 will add planned capacity of 4.7 MTA and 15.6 MTA, respectively, 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 I Trains 1-3, RL I Trains 1-2, RL II Trains 3 and 5, and approximately 49 BCF/MT for QG II Trains 4-5, RL II Train 4, and RL 3 Trains 6-7.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 9.5 thousand acres onshore at year-end. During the year, 1.1 net development wells were drilled and completed.

Thailand

ExxonMobil's net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2005.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi oil concession was 0.5 million acres at year-end 2005, 0.4 million acres onshore and 0.1 million acres offshore. During the year, 6.7 net development wells were completed. The Bab Facility expansion project was completed and commissioning activities were begun for the Northeast Bab Phase I development project.

RUSSIA/CASPIAN

Azerbaijan

At year-end 2005, ExxonMobil's net acreage, located in the Caspian Sea offshore of Azerbaijan, totaled 0.1 million acres. During the year, 0.7 net development wells were completed. At the Azeri-Chirag-Gunashli (ACG) development, the first phase of full-field development at Central Azeri came online in March 2005 and full-field oil production increased to 400 thousand barrels of oil per day (gross) by year-end. Commissioning of the second phase at West Azeri was in-progress at year-end, and construction is under way on the third phase at Deep Water Gunashli.

Kazakhstan

ExxonMobil's net acreage totaled 0.3 million acres onshore and 0.2 million acres offshore at year-end 2005, with 3.2 net exploration and development wells completed during 2005. At Tengiz, construction of the 300 thousand barrels of oil per day (gross) expansion project continued through 2005. Engineering and construction of the initial phase of the Kashagan field continued during 2005.

Russia

ExxonMobil's net acreage holdings at year-end 2005 were 85 thousand acres, all offshore. A total of 3.6 net development wells were completed in the Chayvo field during the year. Production from the field began in October 2005 through an early production system for domestic Russian oil and gas sales. Construction and drilling activities are progressing on Phase 1 full-field production and export systems. Phase 1 facilities 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.

SOUTH AMERICA

Argentina

ExxonMobil's net acreage totaled 0.2 million onshore acres at year-end 2005, and there were 1.5 net development wells completed during the year.

Venezuela

ExxonMobil's net year-end 2005 acreage holdings totaled 0.1 million onshore acres, with 7.1 net development wells completed during the year.

WORLDWIDE EXPLORATION

At year-end 2005, exploration activities were underway in several areas in which ExxonMobil has no established production operations and thus are not included above. A total of 42.8 net million acres were held at year-end 2005, and 0.8 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 1.6 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 separate 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 2005, this upgrading process yielded 0.853 barrels of synthetic crude oil per barrel of crude bitumen. In 2005 about 49 percent of the synthetic crude oil was processed by Edmonton area refineries and the remaining 51 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 $2.8 billion at year end 2005.

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 1,890 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 4,485 million tons of extractable tar sands at an average bitumen grade of 11.2 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 2005 was equivalent to 738 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. The Aurora 2 mining and extraction development became fully operational in 2004. The Upgrader Expansion will be completed in 2006. When completed, this project will increase production capacity to 350 thousand barrels of synthetic crude oil per day (gross).

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ExxonMobil Share of Net Proven Syncrude Reserves(1)

	Synthetic Crude Oil		
	Base Mine and North Mine	Aurora Mine	Total
	(millions of barrels)		
January 1, 2005	217	540	757
Revision of previous estimate	—	—	—
Production	(9)	(10)	(19)
December 31, 2005	208	530	738

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

Syncrude Operating Statistics (total operation)

	2005	2004	2003	2002	2001
Operating Statistics					
Total mined volume (millions of cubic yards)(1)	97.1	100.3	109.2	102.0	118.3
Mined volume to tar sands ratio(1)	1.02	0.94	1.15	1.05	1.15
Tar sands mined (millions of tons)	168.0	188.0	168.0	172.1	181.2
Average bitumen grade (weight percent)	11.1	11.1	11.0	11.2	11.0
Crude bitumen in mined tar sands (millions of tons)	18.6	20.9	18.5	19.2	19.9
Average extraction recovery (percent)	89.1	87.3	88.6	89.9	87.0
Crude bitumen production (millions of barrels)(2)	94.2	103.3	92.3	97.8	97.6
Average upgrading yield (percent)	85.3	85.5	86.0	86.3	84.5
Gross synthetic crude oil produced (millions of barrels)	79.3	88.4	78.4	84.8	82.4
ExxonMobil net share (millions of barrels)(3)	19	22	19	21	19

(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.***

Regarding a previously reported matter, the Corporation and the Texas Commission on Environmental Quality ("TCEQ") have agreed to settle a Notice of Enforcement issued on August 29, 2003, alleging leak detection and repair violations and inadequate notifications of several emissions events as required by air quality regulations at ExxonMobil Oil Corporation's ("EMOC") Beaumont, Texas refinery. Under the terms of the settlement, EMOC has agreed to pay a civil penalty totaling $80,444, half of which will be paid through a supplemental environmental project involving county vehicle retrofits. The parties expect to execute an Agreed Order by the end of March 2006.

Regarding a previously reported matter, the Corporation signed an Administrative Consent Agreement in December 2005 setting forth the terms of settlement of an Administrative Consent Agreement and Enforcement Order regarding underground oil storage tank and air activities received from the Maine Department of Environmental Protection ("MDEP") in March 2005. The MDEP alleged violations at 12 service stations of regulations under the state's Stage II vapor recovery program and underground storage tank program, including those relating to record-keeping, monitoring, equipment, clean-up and testing. The Corporation paid a civil penalty of $269,400 for settlement of the alleged violations. The Agreement is awaiting final execution by the State of Maine.

In another previously reported matter, the Corporation and the Environmental Protection Agency (EPA) filed a Consent Agreement and Final Order with the Administrative Law Judge on January 9, 2006, reflecting the parties' agreement to settle an Administrative Complaint captioned "In the Matter of ExxonMobil Production Company". The EPA had alleged violations of the Clean Water Act at the Hawkins Field (in Wood County, Texas) related to 13 spills of produced water into potential waters of the United States occurring from June 2000 to August 2004. The Corporation has agreed to pay a $31,000 civil penalty and to perform a supplemental environmental project valued at $91,000 relating to enhanced detection of upset conditions at the Hawkins Field.

Refer to the relevant portions of note 14 beginning on page 68 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, 2006	Title (Held Office Since)
R. W. Tillerson	53	Chairman of the Board (2006)
D. D. Humphreys	58	Senior Vice President (2006) and Treasurer (2004)
S. R. McGill	63	Senior Vice President (2004)
J. S. Simon	62	Senior Vice President (2004)
M. W. Albers	49	President, ExxonMobil Development Company (2004)
A. T. Cejka	54	Vice President (2004)
H. R. Cramer	55	Vice President (1999)
P. J. Dingle	57	Vice President (2003)
M. J. Dolan	52	Vice President (2004)
M. E. Foster	62	Vice President (2004)
H. H. Hubble	53	Vice President—Investor Relations and Secretary (2004)
G. L. Kohlenberger	53	Vice President (2002)
C. W. Matthews	61	Vice President and General Counsel (1995)
P. T. Mulva	54	Vice President and Controller (2004)
S. D. Pryor	56	Vice President (2004)
P. E. Sullivan	62	Vice President and General Tax Counsel (1995)

For at least the past five years, Messrs. Cramer, Humphreys, Matthews, McGill, Simon and Sullivan have been employed as executives of the registrant. Mr. Tillerson was a Senior Vice President and then President, a title he continues to hold, before becoming Chairman of the Board. Mr. Humphreys was Vice President and Controller and then Vice President and Treasurer before becoming Senior Vice President and Treasurer. 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. Mulva was Vice President—Investor Relations and Secretary before becoming Vice President and Controller.

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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, 2005.

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 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.

PART II

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

Reference is made to the quarterly information which appears on page 30 of the Financial Section of this report.

Issuer Purchases of Equity Securities for Quarter Ended December 31, 2005

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, 2005	31,108,634	57.96	31,108,634	
November, 2005	30,576,300	57.83	30,576,300	
December, 2005	30,481,964	58.32	30,481,964	
Total	92,166,898	58.04	92,166,898	(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,				
	2005	2004	2003	2002	2001
	(millions of dollars, except per share amounts)				
Sales and other operating revenue(1)(2)	$ 358,955	$ 291,252	$ 237,054	$ 200,949	$ 208,715
(1) Excise taxes included	$ 30,742	$ 27,263	$ 23,855	$ 22,040	$ 21,907
(2) Includes amounts for purchases/sales contracts with the same counterparty.					
Net income					
Income from continuing operations	$ 36,130	$ 25,330	$ 20,960	$ 11,011	$ 15,003
Discontinued operations, net of income tax	—	—	—	449	102
Extraordinary gain, net of income tax	—	—	—	—	215
Cumulative effect of accounting change, net of income tax	—	—	550	—	—
Net income	$ 36,130	$ 25,330	$ 21,510	$ 11,460	$ 15,320
Net income per common share					
Income from continuing operations	$ 5.76	$ 3.91	$ 3.16	$ 1.62	$ 2.19
Discontinued operations, net of income tax	—	—	—	0.07	0.01
Extraordinary gain, net of income tax	—	—	—	—	0.03
Cumulative effect of accounting change, net of income tax	—	—	0.08	—	—
Net income	$ 5.76	$ 3.91	$ 3.24	$ 1.69	$ 2.23
Net income per common share - assuming dilution					
Income from continuing operations	$ 5.71	$ 3.89	$ 3.15	$ 1.61	$ 2.17
Discontinued operations, net of income tax	—	—	—	0.07	0.01
Extraordinary gain, net of income tax	—	—	—	—	0.03
Cumulative effect of accounting change, net of income tax	—	—	0.08	—	—
Net income	$ 5.71	$ 3.89	$ 3.23	$ 1.68	$ 2.21
Cash dividends per common share	$ 1.14	$ 1.06	$ 0.98	$ 0.92	$ 0.91
Total assets	$ 208,335	$ 195,256	$ 174,278	$ 152,644	$ 143,174
Long-term debt	$ 6,220	$ 5,013	$ 4,756	$ 6,655	$ 7,099

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 31 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 40, 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, 2006, beginning on page 46 with the section entitled "Report of Independent Registered Public Accounting Firm" and continuing to page 75;
- Quarterly Information (unaudited) appearing on page 30;
- Supplemental Information on Oil and Gas Exploration and Production Activities (unaudited) appearing on pages 76 through 85; 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 financial officer and principal accounting officer have evaluated the Corporation's disclosure controls and procedures as of December 31, 2005. 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 financial officer and principal accounting 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, 2005.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report beginning on page 46 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 2006 annual meeting of shareholders (the "2006 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 2006 Proxy Statement.

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

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 2006 Proxy Statement.

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

The Registrant has concluded that it has no disclosable matters under this item. Additional information regarding this determination is incorporated by reference to the portion entitled "Director and Officer Relationships" of the section entitled "Election of Directors" in the registrant's 2006 Proxy Statement.

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

Incorporated by reference to the section entitled "Ratification of Independent Auditors" of the registrant's 2006 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 89 of this report.

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FINANCIAL SECTION

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BUSINESS PROFILE

Financial	Earnings After Income Taxes 2005	Earnings After Income Taxes 2004	Average Capital Employed 2005	Average Capital Employed 2004	Return on Average Capital Employed 2005	Return on Average Capital Employed 2004	Capital and Exploration Expenditures 2005	Capital and Exploration Expenditures 2004
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	$ 6,200	$ 4,948	$ 13,491	$ 13,355	46.0	37.0	$ 2,142	$ 1,922
Non-U.S.	18,149	11,727	39,770	37,287	45.6	31.5	12,328	9,793
Total	$24,349	$16,675	$ 53,261	$ 50,642	45.7	32.9	$14,470	$11,715
Downstream								
United States	$ 3,911	$ 2,186	$ 6,650	$ 7,632	58.8	28.6	$ 753	$ 775
Non-U.S.	4,081	3,520	18,030	19,541	22.6	18.0	1,742	1,630
Total	$ 7,992	$ 5,706	$ 24,680	$ 27,173	32.4	21.0	$ 2,495	$ 2,405
Chemical								
United States	$ 1,186	$ 1,020	$ 5,145	$ 5,246	23.1	19.4	$ 243	$ 262
Non-U.S.	2,757	2,408	8,919	9,362	30.9	25.7	411	428
Total	$ 3,943	$ 3,428	$ 14,064	$ 14,608	28.0	23.5	$ 654	$ 690
Corporate and financing	(154)	(479)	24,956	14,916	—	—	80	75
Total	$36,130	$25,330	$116,961	$107,339	31.3	23.8	$17,699	$14,885

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

Operating	2005	2004
	(thousands of barrels daily)	
Net liquids production		
United States	477	557
Non-U.S.	2,046	2,014
Total	2,523	2,571
	(millions of cubic feet daily)	
Natural gas production available for sale		
United States	1,739	1,947
Non-U.S.	7,512	7,917
Total	9,251	9,864
	(thousands of oil-equivalent barrels daily)	
Oil-equivalent production [(1)]	4,065	4,215

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

	2005	2004
	(thousands of barrels daily)	
Petroleum product sales		
United States	2,915	2,872
Non-U.S.	5,342	5,338
Total	8,257	8,210
	(thousands of barrels daily)	
Refinery throughput		
United States	1,794	1,850
Non-U.S.	3,929	3,863
Total	5,723	5,713
	(thousands of metric tons)	
Chemical prime product sales		
United States	10,369	11,521
Non-U.S.	16,408	16,267
Total	26,777	27,788

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FINANCIAL SUMMARY

	2005	2004	2003	2002	2001
		(millions of dollars, except per share amounts)			
Sales and other operating revenue [1]	$358,955	$291,252	$237,054	$200,949	$208,715
Earnings					
Upstream	$ 24,349	$ 16,675	$ 14,502	$ 9,598	$ 10,736
Downstream	7,992	5,706	3,516	1,300	4,227
Chemical	3,943	3,428	1,432	830	707
Corporate and financing	(154)	(479)	1,510	(442)	(142)
Merger-related expenses	—	—	—	(275)	(525)
Income from continuing operations	$ 36,130	$ 25,330	$ 20,960	$ 11,011	$ 15,003
Discontinued operations	—	—	—	449	102
Extraordinary gain	—	—	—	—	215
Accounting change	—	—	550	—	—
Net income	$ 36,130	$ 25,330	$ 21,510	$ 11,460	$ 15,320
Net income per common share					
Income from continuing operations	$ 5.76	$ 3.91	$ 3.16	$ 1.62	$ 2.19
Net income per common share – assuming dilution					
Income from continuing operations	$ 5.71	$ 3.89	$ 3.15	$ 1.61	$ 2.17
Discontinued operations, net of income tax	—	—	—	0.07	0.01
Extraordinary gain, net of income tax	—	—	—	—	0.03
Cumulative effect of accounting change, net of income tax	—	—	0.08	—	—
Net income	$ 5.71	$ 3.89	$ 3.23	$ 1.68	$ 2.21
Cash dividends per common share	$ 1.14	$ 1.06	$ 0.98	$ 0.92	$ 0.91
Net income to average shareholders' equity (percent)	33.9	26.4	26.2	15.5	21.3
Working capital	$ 27,035	$ 17,396	$ 7,574	$ 5,116	$ 5,567
Ratio of current assets to current liabilities	1.58	1.40	1.20	1.15	1.18
Additions to property, plant and equipment	$ 13,839	$ 11,986	$ 12,859	$ 11,437	$ 9,989
Property, plant and equipment, less allowances	$107,010	$108,639	$104,965	$ 94,940	$ 89,602
Total assets	$208,335	$195,256	$174,278	$152,644	$143,174
Exploration expenses, including dry holes	$ 964	$ 1,098	$ 1,010	$ 920	$ 1,175
Research and development costs	$ 712	$ 649	$ 618	$ 631	$ 603
Long-term debt	$ 6,220	$ 5,013	$ 4,756	$ 6,655	$ 7,099
Total debt	$ 7,991	$ 8,293	$ 9,545	$ 10,748	$ 10,802
Fixed-charge coverage ratio (times)	50.2	36.1	30.8	13.8	17.7
Debt to capital (percent)	6.5	7.3	9.3	12.2	12.4
Net debt to capital (percent) [2]	(22.0)	(10.7)	(1.2)	4.4	5.3
Shareholders' equity at year end	$111,186	$101,756	$ 89,915	$ 74,597	$ 73,161
Shareholders' equity per common share	$ 18.13	$ 15.90	$ 13.69	$ 11.13	$ 10.74
Weighted average number of common shares outstanding (millions)	6,266	6,482	6,634	6,753	6,868
Number of regular employees at year end (thousands) [3]	83.7	85.9	88.3	92.5	97.9
CORS employees not included above (thousands) [4]	22.4	19.3	17.4	16.8	19.9

(1) *Sales and other operating revenue includes excise taxes of $30,742 million for 2005, $27,263 million for 2004, $23,855 million for 2003, $22,040 million for 2002 and $21,907 million for 2001. Includes amounts for purchases/sales contracts with the same counterparty.*

(2) *Debt net of cash, excluding restricted cash. The ratio of net debt to capital including restricted cash is (28.3) percent for 2005.*

(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 and 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 and regular disciplined 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	**2005**	**2004**	**2003**
		(millions of dollars)	
Net cash provided by operating activities	$48,138	$40,551	$28,498
Sales of subsidiaries, investments and property, plant and equipment	6,036	2,754	2,290
Cash flow from operations and asset sales	$54,174	$43,305	$30,788

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	**2005**	**2004**	**2003**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	$208,335	$195,256	$174,278
Less liabilities and minority share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(44,536)	(39,701)	(33,597)
Total long-term liabilities excluding long-term debt and equity of minority and preferred shareholders in affiliated companies	(41,095)	(41,554)	(37,839)
Minority share of assets and liabilities	(4,863)	(5,285)	(4,945)
Add ExxonMobil share of debt-financed equity company net assets	3,450	3,914	4,151
Total capital employed	$121,291	$112,630	$102,048
Total corporate sources: debt and equity perspective			
Notes and loans payable	$ 1,771	$ 3,280	$ 4,789
Long-term debt	6,220	5,013	4,756
Shareholders' equity	111,186	101,756	89,915
Less minority share of total debt	(1,336)	(1,333)	(1,563)
Add ExxonMobil share of equity company debt	3,450	3,914	4,151
Total capital employed	$121,291	$112,630	$102,048

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	**2005**	**2004**	**2003**
		(millions of dollars)	
Net income	$ 36,130	$ 25,330	$21,510
Financing costs (after tax)			
Third-party debt	(1)	(137)	(69)
ExxonMobil share of equity companies	(144)	(185)	(172)
All other financing costs – net [1]	(295)	54	1,775
Total financing costs	(440)	(268)	1,534
Earnings excluding financing costs	$ 36,570	$ 25,598	$19,976
Average capital employed	$116,961	$107,339	$95,373
Return on average capital employed – corporate total	31.3%	23.8%	20.9%

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

QUARTERLY INFORMATION

	2005					2004				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Volumes										
					(thousands of barrels daily)					
Production of crude oil and natural gas liquids	2,544	2,468	2,451	2,629	2,523	2,635	2,581	2,505	2,565	2,571
Refinery throughput	5,749	5,727	5,764	5,652	5,723	5,596	5,589	5,809	5,852	5,713
Petroleum product sales	8,229	8,259	8,217	8,322	8,257	8,126	8,023	8,242	8,446	8,210
					(millions of cubic feet daily)					
Natural gas production available for sale	10,785	8,709	7,716	9,822	9,251	11,488	9,061	8,488	10,430	9,864
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production (1)	4,341	3,919	3,737	4,266	4,065	4,550	4,091	3,920	4,303	4,215
					(thousands of metric tons)					
Chemical prime product sales	6,938	6,592	6,955	6,292	26,777	6,792	6,930	7,117	6,949	27,788
Summarized financial data										
					(millions of dollars)					
Sales and other operating revenue (2)	$ 79,475	86,622	96,731	96,127	358,955	$ 66,060	69,220	74,854	81,118	291,252
Gross profit (3)	$ 31,525	32,962	35,336	36,841	136,664	$ 27,619	28,202	29,655	33,560	119,036
Net income	$ 7,860	7,640	9,920	10,710	36,130	$ 5,440	5,790	5,680	8,420	25,330
Per share data										
					(dollars per share)					
Net income per common share	$ 1.23	1.21	1.60	1.72	5.76	$ 0.83	0.89	0.88	1.31	3.91
Net income per common share – assuming dilution	$ 1.22	1.20	1.58	1.71	5.71	$ 0.83	0.88	0.88	1.30	3.89
Dividends per common share	$ 0.27	0.29	0.29	0.29	1.14	$ 0.25	0.27	0.27	0.27	1.06
Common stock prices										
High	$ 64.37	61.74	65.96	63.89	65.96	$ 43.40	45.53	49.79	52.05	52.05
Low	$ 49.25	52.78	57.60	54.50	49.25	$ 39.91	41.43	44.20	48.18	39.91

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

(2) *Includes excise taxes and amounts for purchases/sales with the same counterparty.*

(3) *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 616,344 registered shareholders of ExxonMobil common stock at December 31, 2005. At January 31, 2006, the registered shareholders of ExxonMobil common stock numbered 614,599.

On January 25, 2006, the Corporation declared a $0.32 dividend per common share, payable March 10, 2006.

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FUNCTIONAL EARNINGS	2005	2004	2003
	(millions of dollars, except per share amounts)		
Net Income (U.S. GAAP)			
Upstream			
United States	$ 6,200	$ 4,948	$ 3,905
Non-U.S.	18,149	11,727	10,597
Downstream			
United States	3,911	2,186	1,348
Non-U.S.	4,081	3,520	2,168
Chemical			
United States	1,186	1,020	381
Non-U.S.	2,757	2,408	1,051
Corporate and financing	(154)	(479)	1,510
Income from continuing operations	$ 36,130	$ 25,330	$ 20,960
Accounting change	—	—	550
Net income	$ 36,130	$ 25,330	$ 21,510
Net income per common share	$ 5.76	$ 3.91	$ 3.24
Net income per common share – assuming dilution	$ 5.71	$ 3.89	$ 3.23
Special items included in net income			
Non-U.S. Upstream			
Gain on Dutch gas restructuring	$ 1,620	$ —	$ —
Gain on transfer of Ruhrgas shares	$ —	$ —	$ 1,700
U.S. Downstream			
Allapattah lawsuit provision	$ (200)	$ (550)	$ —
Non-U.S. Downstream			
Sale of Sinopec shares	$ 310	$ —	$ —
Non-U.S. Chemical			
Sale of Sinopec shares	$ 150	$ —	$ —
Joint venture litigation	$ 390	$ —	$ —
Corporate and financing			
U.S. tax settlement	$ —	$ —	$ 2,230

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

FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual future results, including demand growth and mix; capacity increases; production growth and mix; 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 in Item 1A of ExxonMobil's 2005 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. Our 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 87 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 risk-assessed near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Prices for crude oil, natural gas and refined 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 RISK ASSESSMENT

Long-Term Business Outlook

By 2030, the world's population is expected grow to 8 billion, approximately 25 percent higher than today's level. Coincident with this population increase, the Corporation expects worldwide economic growth to average just under 3 percent per year. This combination of population and economic growth should lead to a primary energy demand increase of approximately 50 percent by 2030. The vast majority (80 percent) of the increase is expected to occur in developing countries.

As demand rises, energy efficiency will become increasingly important, with the pace of improvement likely to accelerate. This accelerated pace is the outcome of expected improvements in personal transportation and power generation driven by the introduction of new technologies, as well as a myriad of other improvements which span the residential, commercial and industrial sectors.

Fossil fuels, including coal, are expected to remain the predominant energy sources with approximately 80 percent share of total energy. Oil and gas alone are expected to be about 60 percent. These well-established fuel sources are the only ones with the versatility and scale to meet the majority of the world's growing energy needs. Nuclear power will likely be a growing option to meet electricity needs. Alternative fuels, such as solar and wind power, will grow rapidly, underpinned by government subsidies and mandates. But even with assumptions of robust 10 percent per year growth, solar and wind are expected to represent just 1 percent of the total energy portfolio by 2030.

Oil demand should grow at 1.4 percent per year, primarily due to the increasing number of light duty vehicles in the transportation sector, partly offset by improvements in fuel efficiency. Natural gas and coal are both expected to grow at 1.8 percent annually driven primarily by increased need for electric power generation. The Corporation expects the liquefied natural gas (LNG) market to quintuple by 2030, 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.

The Corporation expects the world's reserve base to grow not only from new discoveries, but also from increases to known reserves. Technology will underpin these increases. The cost to develop these reserves is also 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, or $5 trillion in total.

Upstream

ExxonMobil maintains the largest portfolio of development and exploration 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 production on line, the Corporation expects a shift in the geographic mix of its production volumes between now and 2010. Oil and natural gas output from West Africa, the Caspian, the Middle East and Russia is expected to more than double during the next five years based on current capital project execution plans. Currently, these growth areas account for just over 25 percent of the Corporation's production. By the end of the decade, they are expected to generate about 50 percent of total volumes. The remainder of the Corporation's production is expected to be sourced from established areas, including Europe and North America.

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 25 percent to 35 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 to grow over the period 2006-2010. However, actual volumes will vary from year to year due to timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, asset sales, severe weather events, price effects under production sharing contracts and other factors described in Item 1A of ExxonMobil's 2005 Form 10-K.

Downstream

The downstream industry environment remains very competitive. While refining margins in 2005 were strong, our long-term real refining margins have declined at a rate of about 1 percent per year over the past 20 years. The intense competition in the retail fuels market has similarly driven down real margins by about 4 percent per year. Global refining capacity is expected to grow at about 1 to 2 percent per year through 2010 with Asia Pacific expected to grow at more than 3 percent per year. ExxonMobil assets are well-positioned to supply the growing demand for petroleum products and our continuous focus on making our refineries more efficient and productive has resulted in significant capacity increases to help meet growing demand at a fraction of the cost of building a new refinery. Our capacity growth rate over the past 10 years at existing facilities has been the equivalent of building a new mid-sized refinery every 3 years.

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 factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, seasonality and weather and political climate. This global market and trade flow was particularly evident following the 2005 supply disruptions in the United States caused by hurricanes Katrina and Rita. Fuel prices increased when 25 percent of U.S. refining capacity was shut down. Consumers reduced demand, and additional product imports flowed into the United States. Supply and demand came back into balance quickly, with an associated decline in prices.

The objectives of ExxonMobil's Downstream strategies are to position the Corporation to be the industry leader under a variety of market conditions. These strategies include maintaining best-in-class operations in all aspects of the business, maximizing value from leading-edge technology, capitalizing on integration with other ExxonMobil businesses, and providing high 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 150 thousand barrels per day. ExxonMobil's fuels and lubes marketing business portfolios include operations in over 150 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.

Chemical

Petrochemical demand continued to be supported by a strong global economy in 2005, although reduced product availability and demand in the United States in the aftermath of hurricanes Katrina and Rita impacted sales volumes. Asian demand was strong, driven by economic and industrial production growth. ExxonMobil benefited from continued strong reliability of its operations, as well as a portfolio of products that 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, Chemical also has a diverse portfolio of less-cyclical business lines. Chemical's competitive advantages are achieved through its business mix, broad geographic coverage, investment discipline, integration of chemical capacity with large refining complexes or Upstream gas processing, operational excellence, leading proprietary technology and product application expertise.

REVIEW OF 2005 AND 2004 RESULTS

	2005	2004	2003
		(millions of dollars)	
Income from continuing operations	$36,130	$25,330	$20,960
Accounting change	—	—	550
Net income (U.S. GAAP)	$36,130	$25,330	$21,510

2005

Net income in 2005 of $36,130 million was the highest ever for the Corporation, up $10,800 million from 2004. Net income in 2005 included special items of $2,270 million, consisting of a $1,620 million gain related to the Dutch gas restructuring, a $460 million gain from the sale of the Corporation's stake in Sinopec, a $390 million gain from the resolution of joint venture litigation and a charge of $200 million relating to the Allapattah lawsuit provision.

Total assets at December 31, 2005, of $208 billion increased by approximately $13 billion from 2004, reflecting strong earnings and the Corporation's active investment program, particularly in the Upstream.

2004

Net income in 2004 of $25,330 million was up $3,820 million from 2003. Net income in 2004 included a special charge of $550 million relating to Allapattah. 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.

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

Upstream

	2005	2004	2003
	(millions of dollars)		
Upstream			
United States	$ 6,200	$ 4,948	$ 3,905
Non-U.S.	18,149	11,727	10,597
Total	$24,349	$16,675	$14,502

2005

Upstream earnings totaled $24,349 million, including $1,620 million from a gain related to the Dutch gas restructuring. Absent this, Upstream earnings increased $6,054 million from 2004 due to higher liquids and natural gas realizations partly offset by lower production volume. Oil equivalent production was down 4 percent versus 2004 including the impact of hurricanes Katrina and Rita, as well as divestment and entitlement effects. Excluding these impacts, total oil equivalent production decreased by 1 percent. Liquids production of 2,523 kbd (thousands of barrels daily) decreased by 48 kbd from 2004. Production increases from new projects in West Africa, the North Sea and North America were offset by natural field decline in mature areas, the impact of hurricanes Katrina and Rita, as well as divestment and entitlement effects. Natural gas production of 9,251 mcfd (millions of cubic feet daily) decreased 613 mcfd from 2004. Higher volumes from projects in Qatar, the North Sea and North America were offset by mature field decline, the impact of hurricanes Katrina and Rita, maintenance activity, lower European demand, as well as entitlement and divestment impacts. Improved earnings from both U.S. and non-U.S. Upstream operations were driven by higher liquids and natural gas realizations, partly offset by lower production volumes. Earnings from U.S. Upstream operations for 2005 were $6,200 million, an increase of $1,252 million. Earnings outside the U.S. for 2005, including the $1,620 million gain related to the Dutch gas restructuring, were $18,149 million, an increase of $6,422 million.

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 gain on the transfer of shares in Ruhrgas AG. Absent this, Upstream earnings increased $3,873 million in 2004. Oil equivalent production was flat with 2003 including price-related entitlement effects and divestment impacts. Excluding these impacts, total oil-equivalent production was up 3 percent versus 2003. Liquids production of 2,571 kbd 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 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 from a gain on the transfer of shares in Ruhrgas AG.

Downstream

	2005	2004	2003
	(millions of dollars)		
Downstream			
United States	$3,911	$2,186	$1,348
Non-U.S.	4,081	3,520	2,168
Total	$7,992	$5,706	$3,516

2005

Downstream earnings totaled $7,992 million, including a gain of $310 million for the Sinopec share sale and a special charge of $200 million relating to the Allapattah lawsuit provision. Downstream earnings for 2004 also included a charge of $550 million for Allapattah. Absent these, Downstream earnings increased $1,626 million from 2004 reflecting stronger worldwide refining margins partly offset by weaker marketing margins. Petroleum product sales of 8,257 kbd increased from 8,210 kbd in 2004. Refinery throughput was 5,723 kbd compared with 5,713 kbd in 2004. U.S. Downstream earnings of $3,911 million increased by $1,725 million, including the charges in both years related to Allapattah. Non-U.S. Downstream earnings of $4,081 million, including a gain for the Sinopec share sale, were $561 million higher than 2004.

2004

Downstream earnings totaled $5,706 million, including a special charge of $550 million relating to Allapattah. 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 charge relating to Allapattah, increased by $838 million. Non-U.S. Downstream earnings of $3,520 million were $1,352 million higher than 2003.

Chemical

	2005	2004	2003
	(millions of dollars)		
Chemical			
United States	$1,186	$1,020	$ 381
Non-U.S.	2,757	2,408	1,051
Total	$3,943	$3,428	$1,432

2005

Chemical earnings totaled $3,943 million, including a $390 million gain from the favorable resolution of joint venture litigation and $150 million from a gain on the Sinopec share sale. Absent these, Chemical earnings decreased $25 million from 2004 due to lower volumes, partially offset by higher worldwide margins. Prime product sales were 26,777 kt (thousands of metric tons), a decrease of 1,011 kt from 2004, largely reflecting the impact of hurricanes Katrina and Rita. 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 $1,186 million increased by $166 million. Non-U.S. Chemical earnings increased by $349 million to $2,757 million, including the impact of the gain from the resolution of the joint venture litigation of $390 million and a gain of $150 million on the Sinopec share sale.

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, an increase of 1,221 kt from 2003, reflecting improved worldwide demand. 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.

All Other Segments

	2005	2004	2003
	(millions of dollars)		
All other segments			
Corporate and financing	$(154)	$(479)	$1,510
Accounting change	—	—	550
Total	$(154)	$(479)	$2,060

2005

Corporate and financing expenses were $154 million compared with $479 million in 2004. The decrease of $325 million is mainly due to higher interest income.

2004

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2005	2004
	(millions of dollars)	
Net cash provided by/(used in)		
Operating activities	$ 48,138	$ 40,551
Investing activities	(10,270)	(14,910)
Financing activities	(26,941)	(18,268)
Effect of exchange rate changes	(787)	532
Increase/(decrease) in cash and cash equivalents	$ 10,140	$ 7,905
	(Dec. 31)	
Cash and cash equivalents	$ 28,671	$ 18,531
Cash and cash equivalents – restricted	4,604	4,604
Total cash and cash equivalents	$ 33,275	$ 23,135

Cash and cash equivalents were $28,671 million at the end of 2005, an increase of $10,140 million, including $(787) million of foreign exchange rate effects from the general strengthening of the U.S. dollar in 2005. Including restricted cash and cash equivalents of $4,604 million (see note 3 on page 58 and note 14 on page 68), total cash and cash equivalents were $33,275 million at the end of 2005. 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 in 2004. Including restricted cash and cash equivalents of $4,604 million, total cash and cash equivalents of $23,135 million at the end of 2004 increased $12,509 million during the year. Cash flows from operating, investing and financing activities are discussed below. For additional details, see the Consolidated Statement of Cash Flows on page 51.

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.

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. After a period of production at plateau rates, it is the nature of oil and gas fields eventually to produce at declining rates for the remainder of their economic life. Averaged over all our existing oil and gas fields and without new projects, ExxonMobil’s entitlement production is expected to decline at approximately six percent per year through the end of the decade, consistent with recent historical performance. Decline rates can vary widely by individual field due to a number of factors, including, but not limited to, the type of reservoir, fluid properties, recovery mechanisms, and age of the field. Furthermore, the Corporation’s production entitlements for individual fields can vary with price and contractual terms.

The Corporation has long been successful at offsetting the effects of natural field decline through disciplined investments and anticipates similar results in the future. Projects are in progress or planned to increase production capacity. However, these volume increases are subject to a variety of risks including project start-up timing, operational outages, reservoir performance, crude oil and natural gas prices, severe weather events, and regulatory changes. The Corporation’s cash flows are also highly dependent on crude oil and natural gas prices.

The Corporation's financial strength, as evidenced by its AAA/Aaa debt rating, enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2005 were $17.7 billion, reflecting the corporation's continued active investment program. The Corporation expects spending to continue in this range for the next several years, although actual spending could vary depending on progress of individual projects. 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 cash flows from operating activities.

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

Cash Flow from Operating Activities

2005

Cash provided by operating activities totaled $48.1 billion in 2005, a $7.5 billion increase from 2004. Major sources of funds were net income of $36.1 billion, which increased $10.8 billion, and non-cash provisions of $10.3 billion for depreciation and depletion. Contributing to the increased level of cash provided by operating activities in 2005 was the net timing effect of receipts of notes and accounts receivable and payments of accounts and other payables in a rising price environment.

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 non-cash 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.

Cash Flow from Investing Activities

2005

Cash used in investing activities totaled $10.3 billion in 2005, $4.6 billion lower than 2004. In 2004, the Corporation pledged $4.6 billion as bond collateral for a litigation appeal (see 2004 comments below). Spending for property, plant and equipment increased $1.9 billion. Proceeds from the sales of subsidiaries, investments and property, plant and equipment of $6.0 billion in 2005 increased $3.3 billion, including almost $1.4 billion from the sale of the Corporation's interest in Sinopec.

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 14 on page 68, 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.

Cash Flow from Financing Activities

2005

Cash used in financing activities was $26.9 billion, an increase of $8.6 billion from 2004, reflecting a higher level of purchases of ExxonMobil shares. Dividend payments on common shares increased to $1.14 per share from $1.06 per share and totaled $7.2 billion, a payout of 20 percent. Total consolidated short-term and long-term debt declined $0.3 billion to $8.0 billion at year-end 2005. Shareholders' equity increased $9.5 billion in 2005, to $111.2 billion, reflecting $36.1 billion of net income partly offset by distributions to ExxonMobil shareholders of $7.2 billion of dividends and $16.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding. Shareholders' equity, and net assets and liabilities, also decreased $2.6 billion, representing the foreign exchange translation effects of weaker foreign currencies at the end of 2005 on ExxonMobil's operations outside the U.S.

During 2005, Exxon Mobil Corporation purchased 311 million shares of its common stock for the treasury at a gross cost of $18.2 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 4.2 percent from 6,401 million at the end of 2004 to 6,133 million at the end of 2005. 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.

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 $8.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding. 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 2.5 percent 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.

Commitments

Set forth below is information about the Corporation's commitments outstanding at December 31, 2005. 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 2006	2007-2010	2011 and Beyond	Total
		(millions of dollars)			
Long-term debt [1]	12	$ —	$ 583	$5,637	$6,220
– Due in one year [2]		515	—	—	515
Asset retirement obligations [3]	8	143	788	2,637	3,568
Pension obligations [4]	15	1,582	1,528	4,961	8,071
Operating leases [5]	9	1,505	3,895	1,560	6,960
Unconditional purchase obligations [6]	14	569	1,909	2,098	4,576
Take-or-pay obligations [7]		983	2,740	2,288	6,011
Firm capital commitments [8]		4,105	2,341	1,129	7,575

This table excludes commodity purchase obligations (volumetric commitments but no fixed or minimum price) which are resold shortly after purchase, either in an active, highly liquid market or under long-term, unconditional sales contracts with similar pricing terms. Examples include long-term, noncancelable LNG and natural gas purchase commitments and commitments to purchase refinery products at market prices. Inclusion of such commitments would not be meaningful in assessing liquidity and cash flow, because these purchases will be offset in the same periods by cash received from the related sales transactions.

Notes:

(1) Includes capitalized lease obligations of $197 million. Long-term debt amounts exclude the Corporation's share of equity company debt.

(2) The amount due in one year is included in notes and loans payable of $1,771 million (note 5 on page 58).

(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. For funded pension plans, this difference was $2.8 billion at December 31, 2005 (U.S. $1.2 billion, non-U.S. $1.6 billion). For unfunded plans, this was the ABO amount of $5.3 billion (U.S. $1.1 billion, non-U.S. $4.2 billion). The payments by period include expected contributions to funded pension plans in 2006 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 $4,576 million mainly pertain to pipeline throughput agreements and include $2,324 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $1,248 million, was $3,328 million.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undiscounted obligations of $6,011 million mainly pertain to transportation and refining purchases and include $2,008 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of $1,287 million, totaled $4,724 million.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $7.6 billion. These commitments were predominantly associated with Upstream projects outside the U.S., of which the two largest commitments outstanding at the end of 2005 were $1.9 billion and $1.4 billion associated with the development of crude oil and natural gas resources in Malaysia and Kazakhstan, respectively. The Corporation expects to fund the majority of these commitments through internal cash flow.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2005, for $3,893 million, primarily relating to guarantees for notes, loans and performance under contracts (note 14 on page 68). This included $1,020 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 $2,649 million, representing ExxonMobil's share of obligations of certain equity companies. The below 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.

	Dec. 31, 2005 Equity Company Obligations	Other Third-Party Obligations	Total
	(millions of dollars)		
Guarantees of excise taxes/customs duties under reciprocal arrangements	$ —	$ 1,020	$1,020
Other guarantees	2,649	224	2,873
Total	$ 2,649	$ 1,244	$3,893

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

Financial Strength

On December 31, 2005, unused credit lines for short-term financing totaled approximately $5.4 billion (note 5 on page 58).

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 87 years.

	2005	2004	2003
Fixed-charge coverage ratio (times)	50.2	36.1	30.8
Debt to capital (percent)	6.5	7.3	9.3
Net debt to capital (percent) [(1)]	(22.0)	(10.7)	(1.2)
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 (28.3) percent for 2005.*

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.

The Corporation makes limited use of derivative instruments, which are discussed in Risk Management on page 41 and note 11 on page 62.

Litigation and Other Contingencies

As discussed in note 14 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 and paid. All of the punitive damage claims were consolidated in the civil trial that began in 1994. The first judgment from the United States District Court for the District of Alaska in the amount of $5 billion was vacated by the United States Court of Appeals for the Ninth Circuit as being excessive under the Constitution. The second judgment in the amount of $4 billion was vacated by the Ninth Circuit panel without argument and sent back for the District Court to reconsider in light of the recent U.S. Supreme Court decision in *Campbell v. State Farm*. The most recent District Court judgment for punitive damages was for $4.5 billion plus interest and was entered in January 2004. ExxonMobil and the plaintiffs have appealed this decision to the Ninth Circuit. The Corporation has posted a $5.4 billion letter of credit. Oral arguments were held before the Ninth Circuit on January 27, 2006. Management believes that the likelihood of the judgment being upheld is remote. While it is reasonably possible that a liability may have been incurred from the Exxon Valdez grounding, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

In December 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 in May 2001. In December 2002, the Alabama Supreme Court vacated the $3.5 billion jury verdict. The case was retried and in November 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. In March 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 to the Alabama Supreme Court. 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. In May 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. 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.

In 2001, a Louisiana state court jury awarded compensatory damages of $56 million and punitive damages of $1 billion to a landowner for damage caused by a third party that leased the property from the landowner. The third party provided pipe cleaning and storage services for the Corporation and other entities. The Louisiana Fourth Circuit Court of Appeals reduced the punitive damage award to $112 million in 2005. The Corporation appealed this decision to the Louisiana Supreme Court as it continues to believe that these judgments should be substantially reduced on legal and constitutional grounds. While it is reasonably possible that a liability may have been incurred, 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 2001 that a class of Exxon dealers between March 1983 and August 1994 had been overcharged for gasoline. In June 2003, the Eleventh Circuit Court of Appeals affirmed the judgment and in March 2004, denied a petition for Rehearing En Banc. In October 2004, the U.S. Supreme Court granted review 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. In light of the Supreme Court's decision to grant review of only part of ExxonMobil's appeal, the Corporation took an after-tax charge of $550 million in the third quarter of 2004 reflecting the estimated liability, after considering potential set-offs and defenses for the claims under review by the Supreme Court. In June 2005, the Supreme Court granted the District Court the right to hear the claims of all class members and the Corporation took an after-tax charge of $200 million. Class counsel and ExxonMobil are seeking court approval of a settlement of $1,075 million, pre-tax that would essentially finalize the Corporation's financial obligation in the case; this obligation has been fully accrued. The trial court has preliminarily approved the settlement. Notice has been issued to the class and the final approval hearing will occur in April 2006.

Tax issues for 1986 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

	2005		2004	
	U.S.	Non-U.S.	U.S.	Non-U.S.
		(millions of dollars)		
Upstream [1]	$2,142	$12,328	$1,922	$ 9,793
Downstream	753	1,742	775	1,630
Chemical	243	411	262	428
Other	80	–	66	9
Total	$3,218	$14,481	$3,025	$11,860

(1) *Exploration expenses included.*

Capital and exploration expenditures in 2005 were $17.7 billion, reflecting the Corporation's continued active investment program. The Corporation expects spending to continue in this range for the next several years. Actual spending could vary depending on progress of individual projects.

Upstream spending was up 24 percent to $14.5 billion in 2005, from $11.7 billion in 2004, as a result of higher spending in growth areas such as Russia, the Caspian, Qatar and West Africa. In addition, spending in the U.S., Australia and the North Sea was also higher. During the past three years, Upstream capital and exploration expenditures averaged $12.7 billion. 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 and exploration expenditures are not tracked by the undeveloped and developed proved reserve categories. Capital investments in the Downstream totaled $2.5 billion in 2005, up $0.1 billion from 2004. Chemical capital expenditures were essentially unchanged from 2004.

TAXES

	2005	2004	2003
		(millions of dollars)	
Income taxes	$23,302	$15,911	$11,006
Excise taxes	30,742	27,263	23,855
All other taxes and duties	44,571	43,605	40,107
Total	$98,615	$86,779	$74,968
Total effective tax rate	41.4%	40.3%	36.4%

2005

Income, excise and all other taxes totaled $98.6 billion in 2005, an increase of $11.8 billion or 14 percent from 2004. Income tax expense, both current and deferred, was $23.3 billion, $7.4 billion higher than 2004, reflecting higher pre-tax income in 2005. The effective tax rate was 41.4 percent in 2005, compared to 40.3 percent in 2004. 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 $75.3 billion in 2005 increased $4.4 billion from 2004, reflecting higher prices and foreign exchange effects.

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 2003. 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.

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

ASSET RETIREMENT OBLIGATIONS AND ENVIRONMENTAL COSTS

Asset Retirement Obligations

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 ($165 million for 2005). Over time, the liabilities are accreted for the increase in their present value, with this effect included in expenses ($208 million in 2005). Payments made for asset retirement obligations in 2005 were $193 million, and the ending balance of the obligations recorded on the balance sheet at December 31, 2005, totaled $3,568 million.

Environmental Costs

	2005	2004
	(millions of dollars)	
Capital expenditures	$ 1,240	$ 1,073
Included in expenses	2,089	1,781
Total	$ 3,329	$ 2,854

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 fuels as well as projects to reduce nitrogen oxide and sulfur oxide emissions. ExxonMobil's 2005 worldwide environmental costs for all such preventative and remediation steps were about $3.3 billion, of which $1.2 billion were capital expenditures and $2.1 billion were included in expenses. The total cost for such activities is expected to remain in this range in 2006 and 2007 (with capital expenditures approximately 35 percent of the total).

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 or financial condition. Provisions made in 2005 for environmental liabilities were $487 million ($340 million in 2004), included in the $2.1 billion of 2005 expenses noted above, and the balance sheet reflects accumulated liabilities of $849 million as of December 31, 2005, and $643 million as of December 31, 2004.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations (1)	2005	2004	2003
Crude oil and NGL ($/barrel)	$48.23	$34.76	$26.66
Natural gas ($/kcf)	5.96	4.48	3.98

(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 varied. In the Upstream, based on the 2005 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 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, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivative instruments to mitigate the impact of such changes. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity. The Corporation's limited derivative activities pose no material credit or market risks to ExxonMobil's operations, financial condition or liquidity. Note 11 on page 62 summarizes the fair value of derivatives outstanding at year-end and the gains or losses that have been recognized in net income.

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 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. The Corporation's cash balances exceeded total debt at year-end 2005 and 2004.

The Corporation conducts business in many foreign currencies and is subject to exchange rate risk on cash flows related to sales, expenses, financing and investment transactions. The impacts of fluctuations in exchange rates on ExxonMobil's geographically and functionally diverse operations are varied and often offsetting in amount. The Corporation makes limited use of currency exchange contracts, commodity forwards, swaps and futures contracts to mitigate the impact of changes in currency values and commodity prices. Exposures related to the Corporation's limited use of the above contracts are 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.

RECENTLY ISSUED STATEMENTS OF FINANCIAL ACCOUNTING STANDARDS

Share-based Payment

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 requisite service 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 for the Corporation as of January 1, 2006, for awards granted or modified after that date and for awards granted prior to that date that have not vested. 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 stock option awards have vested. FAS 123R will therefore not materially change the Corporation's existing accounting practices or the amount of share-based compensation recognized in earnings.

The cumulative compensation expense associated with share-based payments made in 2005, 2004 and 2003 has been recognized in the income statement using the "nominal vesting period approach." The full cost of awards given to employees who have retired before the end of the vesting period has been expensed. The use of a "non-substantive vesting period approach" based on the retirement eligibility age, would not be significantly different from the nominal vesting period approach. The non-substantive vesting period approach will be applicable to grants made after the adoption of FAS 123R on January 1, 2006.

Accounting for Purchases and Sales of Inventory with the Same Counterparty

At its September 2005 meeting, the Emerging Issues Task Force (EITF) reached a consensus on 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 exchanges measured at the book value of the item sold. The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold.

The Corporation records in revenues certain crude oil, natural gas, petroleum product and chemical sales where the Corporation contemporaneously negotiated purchases with the same counterparty. The purchases are recorded in crude oil and product purchases. These transactions are commonly called "buy/sell transactions" and are used to ensure that the right crude oil is available to the Corporation's refineries at the right time and that appropriate products are available

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

to meet customer demand. The Corporation's accounting treatment for these buy/sell transactions is consistent with long standing industry practice. The EITF consensus will result in the Corporation's accounts "Sales and other operating revenue" and "Crude oil and product purchases" on the Consolidated Statement of Income being reduced by associated amounts with no impact on net income. All operating segments will be affected by this change, but the largest impacts are in the Downstream. The EITF consensus will become effective beginning no later than the second quarter of 2006.

The purchase/sale amounts included in revenue for 2005, 2004 and 2003 are shown in note 1 on page 52.

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 for calculating unit-of-production depreciation rates and for evaluating 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 include probable reserves. Probable reserves are reserves that are more 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, commercial and market assessment, and detailed analysis of well information such as flow rates and reservoir pressure declines. 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 company reserves), indicating that proved reserves are consistently moved from undeveloped to developed status. 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 and 2005 reserves on the basis of December 31 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 are 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.

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, or (3) changes to underlying price assumptions used in the determination of reserves. 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. Trigger events for impairment evaluation 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 operating losses.

In general, the Corporation does not view temporarily low oil prices as a trigger 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 risk-assessed operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. 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 76 to 85. The standardized measure of discounted future cash flows on pages 84 and 85 is based on the year-end 2005 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 exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Assessing whether a project has made sufficient progress is a subjective area and requires careful consideration of the relevant facts and circumstances. The facts and circumstances that support continued capitalization of suspended wells as of year-end 2005 are disclosed in note 2 to the financial statements on page 55.

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

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 6 on page 59. 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 its 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 of 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 15, pages 70 to 73, 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.

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 2005 was 9.0 percent. This compares to an actual rate of return over the past decade of 11 percent. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pension fund 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 $95 million before tax.

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.

Litigation and Other Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits and tax disputes. These are summarized on pages 38 and 39, and are also included in note 14 on pages 68 and 69.

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. Payments have not had a materially adverse effect on operations or financial condition. 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, include Malaysia, Indonesia, Angola, Nigeria, Equatorial Guinea, Russia 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 financial officer, and principal accounting 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, 2005.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, was audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Rex W. Tillerson	Donald D. Humphreys	Patrick T. Mulva
Chief Executive Officer	Sr. Vice President and Treasurer	Vice President and Controller
	(Principal Financial Officer)	(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PRICEWATERHOUSECOOPERS

To the Shareholders of Exxon Mobil Corporation:

We have completed integrated audits of Exxon Mobil Corporation's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 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 48 to 75 present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidiaries at December 31, 2005, and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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 8 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, 2005, 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, 2005, 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, 2006

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2005	2004 (millions of dollars)	2003
Revenues and other income				
Sales and other operating revenue [(1)] [(2)]		$358,955	$291,252	$237,054
Income from equity affiliates	6	7,583	4,961	4,373
Other income		4,142	1,822	5,311
Total revenues and other income		$370,680	$298,035	$246,738
Costs and other deductions				
Crude oil and product purchases		$185,219	$139,224	$107,658
Production and manufacturing expenses		26,819	23,225	21,260
Selling, general and administrative expenses		14,402	13,849	13,396
Depreciation and depletion		10,253	9,767	9,047
Exploration expenses, including dry holes		964	1,098	1,010
Interest expense		496	638	207
Excise taxes [(1)]	17	30,742	27,263	23,855
Other taxes and duties	17	41,554	40,954	37,645
Income applicable to minority and preferred interests		799	776	694
Total costs and other deductions		$311,248	$256,794	$214,772
Income before income taxes		$ 59,432	$ 41,241	$ 31,966
Income taxes	17	23,302	15,911	11,006
Income from continuing operations		$ 36,130	$ 25,330	$ 20,960
Cumulative effect of accounting change, net of income tax		—	—	550
Net income		$ 36,130	$ 25,330	$ 21,510
Net income per common share *(dollars)*	10			
Income from continuing operations		$ 5.76	$ 3.91	$ 3.16
Cumulative effect of accounting change, net of income tax		—	—	0.08
Net income		$ 5.76	$ 3.91	$ 3.24
Net income per common share – assuming dilution *(dollars)*	10			
Income from continuing operations		$ 5.71	$ 3.89	$ 3.15
Cumulative effect of accounting change, net of income tax		—	—	0.08
Net income		$ 5.71	$ 3.89	$ 3.23

(1) *Sales and other operating revenue includes excise taxes of $30,742 million for 2005, $27,263 million for 2004 and $23,855 million for 2003.*

(2) *Sales and other operating revenue includes $30,810 million for 2005, $25,289 million for 2004 and $20,936 million for 2003 for purchases/sales contracts with the same counterparty. Associated costs are included in crude oil and product purchases. See note 1 on page 52.*

The information on pages 52 through 75 is an integral part of these statements.

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CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2005	Dec. 31 2004
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		$ 28,671	$ 18,531
Cash and cash equivalents – restricted	3, 14	4,604	4,604
Notes and accounts receivable, less estimated doubtful amounts	5	27,484	25,359
Inventories			
Crude oil, products and merchandise	3	7,852	8,136
Materials and supplies		1,469	1,351
Prepaid taxes and expenses		3,262	2,396
Total current assets		$ 73,342	$ 60,377
Investments and advances	7	20,592	18,404
Property, plant and equipment, at cost, less accumulated depreciation and depletion	8	107,010	108,639
Other assets, including intangibles, net		7,391	7,836
Total assets		$208,335	$195,256
Liabilities			
Current liabilities			
Notes and loans payable	5	$ 1,771	$ 3,280
Accounts payable and accrued liabilities	5	36,120	31,763
Income taxes payable		8,416	7,938
Total current liabilities		$ 46,307	$ 42,981
Long-term debt	12	6,220	5,013
Annuity reserves	15	10,220	10,850
Accrued liabilities		6,434	6,279
Deferred income tax liabilities	17	20,878	21,092
Deferred credits and other long-term obligations		3,563	3,333
Equity of minority and preferred shareholders in affiliated companies		3,527	3,952
Total liabilities		$ 97,149	$ 93,500
Commitments and contingencies	14		
Shareholders’ equity			
Benefit plan related balances		$ (1,266)	$ (1,014)
Common stock without par value (9,000 million shares authorized)		5,743	5,067
Earnings reinvested		163,335	134,390
Accumulated other nonowner changes in equity			
Cumulative foreign exchange translation adjustment		979	3,598
Minimum pension liability adjustment		(2,258)	(2,499)
Unrealized gains/(losses) on stock investments		—	428
Common stock held in treasury (1,886 million shares in 2005 and 1,618 million shares in 2004)		(55,347)	(38,214)
Total shareholders’ equity		$111,186	$101,756
Total liabilities and shareholders’ equity		$208,335	$195,256

The information on pages 52 through 75 is an integral part of these statements.

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

	Note Reference Number	2005 Shareholders' Equity	2005 Nonowner Changes in Equity	2004 Shareholders' Equity	2004 Nonowner Changes in Equity	2003 Shareholders' Equity	2003 Nonowner Changes in Equity
				(millions of dollars)			
Benefit plan related balances							
At beginning of year		$ (1,014)		$ (634)		$ (450)	
Restricted stock award		(613)		(555)		(358)	
Amortization		356		173		107	
Other		5		2		67	
At end of year		$ (1,266)		$ (1,014)		$ (634)	
Common stock							
At beginning of year		5,067		4,468		4,217	
Issued		—		—		—	
Other		676		599		251	
At end of year		$ 5,743		$ 5,067		$ 4,468	
Earnings reinvested							
At beginning of year		134,390		115,956		100,961	
Net income for the year		36,130	$ 36,130	25,330	$ 25,330	21,510	$ 21,510
Dividends – common shares		(7,185)		(6,896)		(6,515)	
At end of year		$ 163,335		$ 134,390		$ 115,956	
Accumulated other nonowner changes in equity							
At beginning of year		1,527		(514)		(6,054)	
Foreign exchange translation adjustment		(2,619)	(2,619)	2,177	2,177	4,436	4,436
Minimum pension liability adjustment	15	241	241	(53)	(53)	514	514
Unrealized gains/(losses) on stock investments		—	—	(83)	(83)	590	590
Reclassification adjustment for gain on sale of stock investment included in net income		(428)	(428)	—	—	—	—
At end of year		$ (1,279)		$ 1,527		$ (514)	
Total			$ 33,324		$ 27,371		$ 27,050
Common stock held in treasury							
At beginning of year		(38,214)		(29,361)		(24,077)	
Acquisitions, at cost		(18,221)		(9,951)		(5,881)	
Dispositions		1,088		1,098		597	
At end of year		$ (55,347)		$ (38,214)		$ (29,361)	
Shareholders' equity at end of year		$ 111,186		$ 101,756		$ 89,915	

	Share Activity 2005	2004	2003
		(millions of shares)	
Common stock			
Issued			
At beginning of year	8,019	8,019	8,019
Issued	—	—	—
At end of year	8,019	8,019	8,019
Held in treasury			
At beginning of year	(1,618)	(1,451)	(1,319)
Acquisitions	(311)	(218)	(163)
Dispositions	43	51	31
At end of year	(1,886)	(1,618)	(1,451)
Common shares outstanding at end of year	6,133	6,401	6,568

The information on pages 52 through 75 is an integral part of these statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2005	2004	2003
			(millions of dollars)	
Cash flows from operating activities				
Net income				
Accruing to ExxonMobil shareholders		$ 36,130	$ 25,330	$ 21,510
Accruing to minority and preferred interests		799	776	694
Cumulative effect of accounting change, net of income tax		—	—	(550)
Adjustments for noncash transactions				
Depreciation and depletion		10,253	9,767	9,047
Deferred income tax charges/(credits)		(429)	(1,134)	1,827
Annuity provisions		254	886	(1,489)
Accrued liability provisions		398	806	264
Dividends received greater than/(less than) equity in current earnings of equity companies		(734)	(1,643)	(402)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) – Notes and accounts receivable		(3,700)	(472)	(1,286)
– Inventories		(434)	(223)	(100)
– Prepaid taxes and expenses		(7)	11	42
Increase/(reduction) – Accounts and other payables		7,806	6,333	1,130
Net (gain) on asset sales and Ruhrgas transaction	4	(1,980)	(268)	(2,461)
All other items – net		(218)	382	272
Net cash provided by operating activities		$ 48,138	$ 40,551	$ 28,498
Cash flows from investing activities				
Additions to property, plant and equipment		$(13,839)	$(11,986)	$(12,859)
Sales of subsidiaries, investments and property, plant and equipment	4	6,036	2,754	2,290
Increase in restricted cash and cash equivalents	3, 14	—	(4,604)	—
Additional investments and advances		(2,810)	(2,287)	(809)
Collection of advances		343	1,213	536
Net cash used in investing activities		$(10,270)	$(14,910)	$(10,842)
Cash flows from financing activities				
Additions to long-term debt		$ 195	$ 470	$ 127
Reductions in long-term debt		(81)	(562)	(914)
Additions to short-term debt		377	450	715
Reductions in short-term debt		(687)	(2,243)	(1,730)
Additions/(reductions) in debt with less than 90-day maturity		(1,306)	(66)	(322)
Cash dividends to ExxonMobil shareholders		(7,185)	(6,896)	(6,515)
Cash dividends to minority interests		(293)	(215)	(430)
Changes in minority interests and sales/(purchases) of affiliate stock		(681)	(215)	(247)
Common stock acquired		(18,221)	(9,951)	(5,881)
Common stock sold		941	960	434
Net cash used in financing activities		$(26,941)	$(18,268)	$(14,763)
Effects of exchange rate changes on cash		$ (787)	$ 532	$ 504
Increase/(decrease) in cash and cash equivalents		$ 10,140	$ 7,905	$ 3,397
Cash and cash equivalents at beginning of year		18,531	10,626	7,229
Cash and cash equivalents at end of year		$ 28,671	$ 18,531	$ 10,626

The information on pages 52 through 75 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 2005 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 ownership percentage 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 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.

At its September 2005 meeting, the Emerging Issues Task Force (EITF) reached a consensus on 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 exchanges measured at the book value of the item sold. The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold.

The Corporation records in revenues certain crude oil, natural gas, petroleum product and chemical sales where the Corporation contemporaneously negotiated purchases with the same counterparty. The purchases are recorded in crude oil and product purchases. These transactions are commonly called "buy/sell transactions" and are used to ensure that the right crude oil is available to the Corporation's refineries at the right time and that appropriate products are available to meet customer demand. The Corporation's accounting treatment for these buy/sell transactions is consistent with long standing industry practice. The EITF consensus will result in the Corporation's accounts "Sales and other operating revenue" and "Crude oil and product purchases" on the Consolidated Statement of Income being reduced by associated amounts with no impact on net income. All operating segments will be affected by this change, but the largest impacts are in the Downstream. The EITF consensus will become effective, beginning no later than the second quarter of 2006.

The purchase/sale amounts included in revenue for 2005, 2004 and 2003 are shown below along with total "Sales and other operating revenue" to provide context.

	2005	2004	2003
		(millions of dollars)	
Sales and other operating revenue	$358,955	$291,252	$237,054
Amounts included in sales and other operating revenue for purchases/sales contracts with the same counterparty *(1)*	30,810	25,289	20,936
Percent of sales and other operating revenue	9%	9%	9%

(1) *Associated costs are in "Crude oil and product purchases"*

Derivative Instruments. The Corporation makes limited use of derivative instruments. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged 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 that arise from existing assets, liabilities and transactions.

The gains and losses resulting from changes in the fair value of derivatives are recorded in income. In some cases, the Corporation designates derivatives as fair value hedges, in which case the gains and losses are offset in income by the gains and losses arising from changes in the fair value of the underlying hedged items.

The Corporation has certain long-term sales and purchase contracts entered into in the normal course of business that are deemed to be derivative instruments. Gains and losses arising from these contracts are calculated by the difference between the contract prices and market prices and are recognized in income.

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.

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 carries as an asset exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. 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 the amount of proved developed reserves of oil, gas and other minerals that are 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 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, Russia and the Middle East. For all operations, gains or losses on remeasuring foreign currency transactions into functional currency are included in income.

Share-Based Payments. Effective January 1, 2003, the Corporation adopted for all employee share-based awards granted after that date, the recognition provisions of Statement of Financial Accounting Standards No. 123 (FAS 123), "Accounting for Share-Based Compensation." In accordance with FAS 123, compensation expense for awards granted on or after January 1, 2003, have been measured by the fair value of the award at the date of grant and recognized over the requisite service 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 share-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 has been recognized in income for these awards. In 2002, the Corporation began issuing restricted stock as share-based compensation in lieu of stock options. Compensation expense for these awards is based on the price of stock when it is granted and is recognized in income over the requisite service period, which is the same method of accounting as under FAS 123. The net income per share for 2003 through 2005 would be unchanged if the provisions of FAS 123 had been adopted for all prior years.

In December 2004, the Financial Accounting Standards Board (FASB) issued a revised Statement of Financial Accounting Standards No. 123 (FAS 123R), "Share-based Payment", which will become effective for the Corporation as of January 1, 2006. Adoption of FAS 123R will not materially change the Corporation's existing accounting practices or the amount of share-based compensation recognized in earnings.

2. Accounting for Suspended Exploratory Well Costs

Effective July 1, 2005, the Corporation adopted Financial Accounting Standards Board Staff Position FAS 19-1 (FSP 19-1), "Accounting for Suspended Well Costs." FSP 19-1 amended Statement of Financial Accounting Standards No. 19 (FAS 19), "Financial Accounting and Reporting by Oil and Gas Producing Companies," 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. There were no capitalized exploratory well costs charged to expense upon the adoption of FSP 19-1.

Prior to the adoption of FSP 19-1, the Corporation carried as an asset the cost of drilling exploratory wells that found sufficient quantities of reserves to justify their completion as producing wells if the required capital expenditure was made and drilling of additional exploratory wells was under way or firmly planned for the near future. Once exploration activities demonstrated that sufficient quantities of commercially producible reserves had been discovered, continued capitalization was dependent on project reviews, which took place at least annually, to ensure that satisfactory progress toward ultimate development of the reserves was being achieved. Exploratory well costs not meeting these criteria were charged to expense.

The following two tables provide details of the changes in the balance of suspended exploratory well costs as well as an aging summary of those costs.

Change in capitalized suspended exploratory well costs:

	2005	2004	2003
		(millions of dollars)	
Balance beginning at January 1	$1,070	$1,093	$1,193
Additions pending the determination of proved reserves	233	139	217
Charged to expense	(62)	(98)	(238)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(82)	(92)	(123)
Foreign exchange/other	(20)	28	44
Ending balance	$1,139	$1,070	$1,093
Ending balance attributed to equity companies included above	$ 2	$ 1	$ 30

Period end capitalized suspended exploratory well costs:

	2005	2004	2003
		(millions of dollars)	
Capitalized for a period of one year or less	$ 233	$ 139	$ 217
Capitalized for a period of between one and five years	485	510	453
Capitalized for a period of between five and ten years	167	172	162
Capitalized for a period of greater than ten years	254	249	261
Capitalized for a period greater than one year – subtotal	$ 906	$ 931	$ 876
Total	$1,139	$1,070	$1,093

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a numerical breakdown of the number of projects with suspended exploratory well costs which had their first capitalized well drilled in the preceding 12 months and those that have had exploratory well costs capitalized for a period greater than 12 months.

	2005	2004	2003
Number of projects with first capitalized well drilled in the preceding 12 months	16	8	13
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	56	61	76
Total	72	69	89

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Of the 56 projects that have exploratory well costs capitalized for a period greater than twelve months as of December 31, 2005, 18 projects have drilling in the preceding twelve months or exploratory activity planned in the next two years, while the remaining 38 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 38 projects which total $561 million.

Country/Project	Dec. 31, 2005	Years Wells Drilled	Comment
	(millions of dollars)		
Angola			
– Marimba	$ 11	2001	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	2001 - 2002	Development awaiting capacity in existing/planned infrastructure; planned subsea tieback to floating production system; submission of Declaration of Commerciality in 2005.
– Orquidea/Violeta	6	1999 - 2001	Planned subsea tieback to floating production system; high-resolution 3-D seismic survey in 2004; further technical evaluation and reservoir studies were conducted in 2005.
Australia			
– Gorgon/Jansz	69	1980 - 2003	Gorgon and Jansz resources to be developed as integrated LNG project; Barrow Island land access rights for onshore plant secured in 2003; co-venturers combined their resources and redistributed their equity interests in 2005 with governmental approval; initial project funding and engineering began in 2005.
– Kipper/East Pilchard	10	1986 - 2001	Bass Strait project in design phase; planned tie-in to existing platform; initial Kipper funding began in 2005 following execution of Memorandum of Understanding between co-venturers; development of East Pilchard phase awaiting capacity in existing/planned infrastructure.
– Whiptail	3	2004	Progressing development concept with planned subsea tieback to existing Bass Strait platform.
Canada			
– Hebron	32	1999 - 2000	Progressing development concept with co-venturer following resolution of the Joint Operating Agreement in 2005; recent efforts focused on further technical evaluation of wells and reservoir using seismic reprocessing and well core analysis; initial project funding and engineering began in 2005.
Indonesia			
– Cepu	41	1998 - 2001	Memorandum of Understanding and a Production Sharing Contract were signed in 2005 that extend the license term for 30 years; other agreements are progressing with the Government of Indonesia; initial project funding and engineering began in 2001, with development anticipated upon conclusion of negotiations.
– Natuna	118	1981 - 1983	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; further technical evaluation and gas marketing activities were progressed in 2005, including discussions with potential customers.

Country/Project	Dec. 31, 2005	Years Wells Drilled	Comment
	(millions of dollars)		
Nigeria			
– Etoro-Isobo	9	2002	Offshore satellite development which will tie back to an existing production facility.
– Other (5 projects)	15	2001 - 2002	Actively pursuing development of several additional offshore satellite discoveries which will tie back to existing production facilities.
Norway			
– Lavrans	20	1995 - 1999	Development awaiting capacity in existing/planned infrastructure; planned subsea tieback to existing floating production system; evaluation of phased ullage filling scenarios is progressing.
– Skarv/Idun	27	1998 - 2002	Planned subsea tieback to floating production system; the export infrastructure and development plan was agreed to with partners in 2005; submission of Plan of Development to the government anticipated in 2006; initial project funding and engineering began in 2005.
– Other (4 projects)	6	1992 - 2002	Progressing several smaller North Sea developments.
Papua New Guinea			
– Hides	35	1993 - 1998	Early engineering studies complete; negotiations with customers on sales terms are in progress; initial project funding and engineering began in 2004; reservoir pressure data acquired in 2005 for ongoing technical evaluation.
Russia			
– Sakhalin 1, Phase 3	26	1996 - 1998	Actively progressing third phase of the Sakhalin-1 project to utilize capacity in facilities and infrastructure in Phase 1; Phase 1 development underway with first production in 2005 and additional development drilling in 2006; progressing Phase 3 development concept with co-venturers and government; plan to conduct further technical evaluation and reservoir studies in 2006.
United Kingdom			
– Phyllis	9	2004	Assessing co-development option with nearby 2005 Barbara discovery.
– Puffin	37	1981 - 1986	Development awaiting capacity in existing infrastructure; planned tieback to existing U.K. North Sea production facility.
– Starling	8	2003	Planned subsea tieback to existing U.K. North Sea facilities; project funding anticipated in 2006.
– Other (2 projects)	3	2002 - 2003	Progressing smaller North Sea developments.
United States			
– Point Thomson	28	1977 - 1980	Progressing development option consisting of tie-in to proposed Alaska gas pipeline; negotiations of gas pipeline fiscal terms with state of Alaska ongoing; conceptual engineering planned for 2006.
Other			
– Various (9 projects)	36	1979 - 2004	Projects primarily awaiting capacity in existing or planned infrastructure.
Total (38 projects)	$561		

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3. Miscellaneous Financial Information

Research and development costs totaled $712 million in 2005, $649 million in 2004 and $618 million in 2003.

Net income included aggregate foreign exchange transaction losses of $138 million in 2005 and gains of $69 million in 2004 and $11 million in 2003.

In 2005, 2004 and 2003, net income included gains of $215 million, $227 million and $255 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 $15.4 billion and $9.8 billion at December 31, 2005, and 2004, respectively.

Crude oil, products and merchandise as of year-end 2005 and 2004 consist of the following:

	2005	2004
	(billions of dollars)	
Petroleum products	$ 3.2	$ 3.4
Crude oil	2.2	2.3
Chemical products	2.1	2.1
Gas/other	0.3	0.3
Total	$ 7.8	$ 8.1

Restricted cash and cash equivalents were $4,604 million at December 31, 2005, 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 38 and note 14 on page 68 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.

4. 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 cash from operating activities on the Consolidated Statement of Cash Flows, the “Net (gain) on asset sales and Ruhrgas transaction” in 2005 includes the before tax gain from the Corporation’s sale of its investment in Sinopec and other assets, primarily Upstream producing properties. The gain is reported in “Other income” on the Consolidated Statement of Income.

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. Upon receipt of regulatory approvals in 2003, a gain of $1,700 million after tax was recognized in net income. An elimination of the pre-tax gain of $2,240 million is included in 2003 cash flow from operating activities. Cash generated of $1,466 million 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.

During 2005, Mobil Services (Bahamas) Ltd. issued variable notes due in 2035 to a consolidated ExxonMobil affiliate. This affiliate was later deconsolidated and the notes were classified as long-term debt. Therefore, this loan did not result in an “Additions to long-term debt” in the Consolidated Statement of Cash Flows.

Cash payments for interest were: 2005 – $473 million, 2004 – $328 million, and 2003 – $429 million. Cash payments for income taxes were: 2005 – $22,535 million, 2004 – $13,510 million, and 2003 – $ 8,149 million.

5. Additional Working Capital Information

	Dec. 31 2005	Dec. 31 2004
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $321 million and $332 million	$23,858	$20,712
Other, less reserves of $44 million and $40 million	3,626	4,647
Total	$27,484	$25,359
Notes and loans payable		
Bank loans	$ 790	$ 839
Commercial paper	291	1,491
Long-term debt due within one year	515	608
Other	175	342
Total	$ 1,771	$ 3,280
Accounts payable and accrued liabilities		
Trade payables	$22,788	$18,186
Payables to equity companies	2,451	1,871
Accrued taxes other than income taxes	5,607	6,055
Other	5,274	5,651
Total	$36,120	$31,763

On December 31, 2005, unused credit lines for short-term financing totaled approximately $5.4 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, 2005, and 2004, was 4.9

percent and 3.5 percent, respectively.

6. 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 52). 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, 22 percent and 18 percent in the years 2005, 2004 and 2003, respectively.

	2005		2004		2003	
Equity Company Financial Summary	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**
			(millions of dollars)			
Total revenues	$88,003	$ 31,395	$72,872	$ 26,359	$63,651	$ 23,667
Income before income taxes	$24,070	$ 9,809	$15,278	$ 6,141	$11,432	$ 5,356
Income taxes	5,574	2,226	3,257	1,180	1,871	983
Income from continuing operations	$18,496	$ 7,583	$12,021	$ 4,961	$ 9,561	$ 4,373
Cumulative effect of accounting change, net of income tax	—	—	—	—	74	35
Net income	$18,496	$ 7,583	$12,021	$ 4,961	$ 9,635	$ 4,408
Current assets	$24,931	$ 8,645	$21,835	$ 7,803	$19,334	$ 7,386
Property, plant and equipment, less accumulated depreciation	50,622	17,149	46,236	15,793	40,895	15,034
Other long-term assets	6,900	3,919	6,600	4,166	5,820	2,694
Total assets	$82,453	$ 29,713	$74,671	$ 27,762	$66,049	$ 25,114
Short-term debt	$ 3,412	$ 1,179	$ 4,109	$ 1,348	$ 3,402	$ 1,336
Other current liabilities	15,330	5,414	14,463	5,397	13,394	5,112
Long-term debt	13,419	2,271	10,477	2,566	7,997	2,815
Other long-term liabilities	7,477	3,153	6,489	2,910	6,738	3,215
Advances from shareholders	14,390	5,580	12,339	3,799	11,092	3,091
Net assets	$28,425	$ 12,116	$26,794	$ 11,742	$23,426	$ 9,545

A list of significant equity companies as of December 31, 2005, 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	25
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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7. Investments and Advances

	Dec. 31 2005	Dec. 31 2004
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	$12,116	$11,742
Advances	5,580	3,799
	$17,696	$15,541
Companies carried at cost or less and stock investments carried at fair value	1,732	1,931
	$19,428	$17,472
Long-term receivables and miscellaneous investments at cost or less	1,164	932
Total	$20,592	$18,404

8. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	Dec. 31, 2005 Cost	Dec. 31, 2005 Net	Dec. 31, 2004 Cost	Dec. 31, 2004 Net
	(millions of dollars)			
Upstream	$ 148,844	$ 62,817	$ 148,024	$ 62,013
Downstream	59,338	28,029	62,014	29,810
Chemical	21,055	9,304	21,777	10,049
Other	11,057	6,860	10,607	6,767
Total	$ 240,294	$ 107,010	$ 242,422	$ 108,639

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 $133,284 million at the end of 2005 and $133,783 million at the end of 2004. Interest capitalized in 2005, 2004 and 2003 was $434 million, $500 million and $490 million, respectively.

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.” 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. 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.

The cumulative adjustment for the change in accounting principle reported in 2003 was after-tax income of $550 million.

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

	2005	2004
	(millions of dollars)	
Beginning balance	$3,610	$3,440
Accretion expense and other provisions	208	136
Payments made	(193)	(201)
Liabilities incurred	165	143
Foreign currency translation/other	(222)	92
Ending balance	$3,568	$3,610

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9. Leased Facilities

At December 31, 2005, 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 2005, 2004 and 2003 totaled $2,790 million, $2,491 million and $2,298 million, respectively, after being reduced by related rental income of $176 million, $136 million and $141 million, respectively. Minimum rental expenditures totaled $2,847 million in 2005, $2,501 million in 2004 and $2,319 million in 2003.

	Minimum Commitment	Related Rental Income
	(millions of dollars)	
2006	$ 1,505	$ 48
2007	1,406	43
2008	1,089	38
2009	761	33
2010	639	30
2011 and beyond	1,560	45
Total	$ 6,960	$ 237

10. Earnings Per Share

	2005	2004	2003
Net income per common share			
Income from continuing operations *(millions of dollars)*	$36,130	$25,330	$20,960
Weighted average number of common shares outstanding *(millions of shares)*	6,266	6,482	6,634
Net income per common share *(dollars)*			
Income from continuing operations	$ 5.76	$ 3.91	$ 3.16
Cumulative effect of accounting change, net of income tax	—	—	0.08
Net income	$ 5.76	$ 3.91	$ 3.24
Net income per common share – assuming dilution			
Income from continuing operations *(millions of dollars)*	$36,130	$25,330	$20,960
Weighted average number of common shares outstanding *(millions of shares)*	6,266	6,482	6,634
Effect of employee stock-based awards	56	37	28
Weighted average number of common shares outstanding – assuming dilution	6,322	6,519	6,662
Net income per common share *(dollars)*			
Income from continuing operations	$ 5.71	$ 3.89	$ 3.15
Cumulative effect of accounting change, net of income tax	—	—	0.08
Net income	$ 5.71	$ 3.89	$ 3.23
Dividends paid per common share *(dollars)*	$ 1.14	$ 1.06	$ 0.98

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11. 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, 2005, and 2004, was $7.0 billion and $5.9 billion, respectively, as compared to recorded book values of $6.2 billion and $5.0 billion.

The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivatives to mitigate the impact of such changes. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity. The Corporation's limited derivative activities pose no material credit or market risks to ExxonMobil's operations, financial condition or liquidity.

The estimated fair values of derivatives outstanding and recorded on the balance sheet are shown in the table below. This is the amount that the Corporation would have paid to, or received from, third parties if these derivatives had been settled in the open market. The majority of the 2005 amount resulted from long-term U.K. gas sales and purchase contracts entered into in the normal course of business that are deemed to be derivative instruments. The amounts reflect the increase in U.K. market gas prices relative to the prices included in the contracts. These contracts are expected to be settled in full by physical delivery of the underlying commodity.

Derivatives	2005	2004	2003
	(millions of dollars)		
Net receivable/(payable)	$(426)	$ 6	$(17)
Net gain/(loss), before tax	$(312)	$38	$ 4
Net gain/(loss), after tax	$(188)	$40	$ 3

The fair value of derivatives outstanding at year-end 2005 and loss recognized during the year are immaterial in relation to the Corporation's year-end cash balance of $28.7 billion, total assets of $208.3 billion or net income for the year of $36.1 billion.

12. Long-Term Debt

At December 31, 2005, long-term debt consisted of $6,014 million due in U.S. dollars and $206 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 $515 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, 2006, in millions of dollars, are: 2007 – $99, 2008 – $284, 2009 – $111 and 2010 – $89. At December 31, 2005, the Corporation's unused long-term credit lines were not material.

Summarized long-term borrowings at year-end 2005 and 2004 were as shown in the table below:

	2005	2004
	(millions of dollars)	
Exxon Capital Corporation (1)		
6.125% Guaranteed notes due 2008	$ 160	$ 160
SeaRiver Maritime Financial Holdings, Inc. (1)		
Guaranteed debt securities due 2006-2011 (2)	65	75
Guaranteed deferred interest debentures due 2012		
– Face value net of unamortized discount plus accrued interest	1,391	1,249
Mobil Services (Bahamas) Ltd.		
Variable notes due 2035 (3)	972	—
Variable notes due 2034 (4)	311	311
Mobil Corporation		
8.625% debentures due 2021	248	248
Industrial revenue bonds due 2007-2033 (5)	1,700	1,702
Other U.S. dollar obligations (6)	1,023	719
Other foreign currency obligations	153	195
Capitalized lease obligations (7)	197	354
Total long-term debt	$ 6,220	$ 5,013

(1) *Additional information is provided for these subsidiaries on pages 63 to 67.*

(2) *Average effective interest rate of 3.3% in 2005 and 1.5% in 2004.*

(3) *Average effective interest rate of 3.7% in 2005.*

(4) *Average effective interest rate of 3.3% in 2005, and 2.0% in 2004.*

(5) *Average effective interest rate of 2.8% in 2005 and 1.8% in 2004.*

(6) *Average effective interest rate of 6.7% in 2005 and 6.0% in 2004.*

(7) *Average imputed interest rate of 7.5% in 2005 and 7.4% in 2004.*

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, 2005) of Exxon Capital Corporation and the deferred interest debentures due 2012 ($1,391 million long-term) and the debt securities due 2006 to 2011 ($65 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.

Condensed consolidated statement of income for 12 months ended December 31, 2005	Exxon Mobil Corporation Parent Guarantor	Exxon Capital Corporation	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries	Consolidating and Eliminating Adjustments	Consolidated
			(millions of dollars)			
Revenues and other income						
Sales and other operating revenue, including excise taxes	$ 15,081	$ —	$ —	$ 343,874	$ —	$ 358,955
Income from equity affiliates	32,996	—	6	7,584	(33,003)	7,583
Other income	834	—	—	3,308	—	4,142
Intercompany revenue	33,546	51	56	274,706	(308,359)	—
Total revenues and other income	82,457	51	62	629,472	(341,362)	370,680
Costs and other deductions						
Crude oil and product purchases	30,451	—	—	447,251	(292,483)	185,219
Production and manufacturing expenses	7,177	3	—	24,856	(5,217)	26,819
Selling, general and administrative expenses	2,434	2	—	12,478	(512)	14,402
Depreciation and depletion	1,341	3	—	8,909	—	10,253
Exploration expenses, including dry holes	137	—	—	827	—	964
Interest expense	2,723	15	159	7,775	(10,176)	496
Excise taxes	—	—	—	30,742	—	30,742
Other taxes and duties	21	—	—	41,533	—	41,554
Income applicable to minority and preferred interests	—	—	—	799	—	799
Total costs and other deductions	44,284	23	159	575,170	(308,388)	311,248
Income before income taxes	38,173	28	(97)	54,302	(32,974)	59,432
Income taxes	2,043	11	(36)	21,284	—	23,302
Income from continuing operations	36,130	17	(61)	33,018	(32,974)	36,130
Accounting change, net of income tax	—	—	—	—	—	—
Net income	$ 36,130	$ 17	$ (61)	$ 33,018	$ (32,974)	$ 36,130

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	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
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
Accounting change, net of income tax	—	—	—	—	—	—
Net income	$ 25,330	$ 2	$ (59)	$ 23,221	$ (23,164)	$ 25,330
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
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
Accounting change, net of income tax	550	—	—	481	(481)	550
Net income	$ 21,510	$ 4	$ (67)	$ 18,699	$ (18,636)	$ 21,510

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, 2005						
Cash and cash equivalents	$ 12,076	$ —	$ —	$ 16,595	$ —	$ 28,671
Cash and cash equivalents – restricted	4,604	—	—	—	—	4,604
Notes and accounts receivable – net	2,183	—	—	25,301	—	27,484
Inventories	1,241	—	—	8,080	—	9,321
Prepaid taxes and expenses	117	—	—	3,145	—	3,262
Total current assets	20,221	—	—	53,121	—	73,342
Investments and advances	163,033	—	375	403,173	(545,989)	20,592
Property, plant and equipment – net	15,537	92	—	91,381	—	107,010
Other long-term assets	1,257	—	74	6,060	—	7,391
Intercompany receivables	14,569	1,041	1,768	377,176	(394,554)	—
Total assets	$ 214,617	$ 1,133	$ 2,217	$ 930,911	$ (940,543)	$ 208,335
Notes and loans payable	$ 446	$ —	$ 10	$ 1,315	$ —	$ 1,771
Accounts payable and accrued liabilities	3,137	3	1	32,979	—	36,120
Income taxes payable	553	1	2	7,860	—	8,416
Total current liabilities	4,136	4	13	42,154	—	46,307
Long-term debt	270	160	1,456	4,334	—	6,220
Deferred income tax liabilities	2,909	27	257	17,685	—	20,878
Other long-term liabilities	5,412	13	—	18,319	—	23,744
Intercompany payables	90,705	121	383	303,345	(394,554)	—
Total liabilities	103,432	325	2,109	385,837	(394,554)	97,149
Earnings reinvested	163,335	23	(361)	108,770	(108,432)	163,335
Other shareholders' equity	(52,150)	785	469	436,304	(437,557)	(52,149)
Total shareholders' equity	111,185	808	108	545,074	(545,989)	111,186
Total liabilities and shareholders' equity	$ 214,617	$ 1,133	$ 2,217	$ 930,911	$ (940,543)	$ 208,335
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

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	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 cash flows for 12 months ended December 31, 2005						
Cash provided by/(used in) operating activities	$ 11,538	$ 11	$ 129	$ 42,088	$ (5,628)	$ 48,138
Cash flows from investing activities						
Additions to property, plant and equipment	(1,296)	—	—	(12,543)	—	(13,839)
Sales of long-term assets	314	—	—	5,722	—	6,036
Increase in restricted cash and cash equivalents	—	—	—	—	—	—
Net intercompany investing	15,483	49	(173)	(15,557)	198	—
All other investing, net	1	—	—	(2,468)	—	(2,467)
Net cash provided by/(used in) investing activities	14,502	49	(173)	(24,846)	198	(10,270)
Cash flows from financing activities						
Additions to short- and long-term debt	—	—	—	572	—	572
Reductions in short- and long-term debt	—	—	(10)	(758)	—	(768)
Additions/(reductions) in debt with less than 90-day maturity	446	—	—	(1,752)	—	(1,306)
Cash dividends	(7,185)	—	—	(5,628)	5,628	(7,185)
Common stock acquired	(18,221)	—	—	—	—	(18,221)
Net intercompany financing activity	—	(64)	(21)	208	(123)	—
All other financing, net	941	—	75	(974)	(75)	(33)
Net cash provided by/(used in) financing activities	(24,019)	(64)	44	(8,332)	5,430	(26,941)
Effects of exchange rate changes on cash	—	—	—	(787)	—	(787)
Increase/(decrease) in cash and cash equivalents	$ 2,021	$ (4)	$ —	$ 8,123	$ —	$ 10,140
Condensed consolidated statement of cash flows for 12 months ended December 31, 2004						
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 consolidating financial information related to guaranteed securities issued by subsidiaries

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
			(millions of dollars)			
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

13. 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 188,928 thousand at the end of 2005.

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 11,071 thousand, 11,374 thousand and 10,381 thousand shares of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2005, 2004 and 2003, respectively. These shares are issued to employees from treasury stock. The total compensation expense is recognized over the requisite service 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 table on the following page provides additional details on restricted stock awards in 2003, 2004, and 2005.

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

Restricted Stock and Units	2005	2004	2003
		(thousands)	
Shares/Units:			
Granted	11,071	11,374	10,381
Issued and outstanding at end of year	29,530	23,159	13,089
Grant price	$ 58.43	$ 51.07	$ 36.11
		(millions of dollars)	
Value:			
Restricted stock and units settled in stock granted	$ 611	$ 554	$ 357
Units settled in cash granted	36	27	18
Total grant	$ 647	$ 581	$ 375

Changes that occurred in stock options in 2005, 2004 and 2003 are summarized below (shares in thousands):

	2005		2004		2003	
Stock Options	Shares	Avg. Exercise Price	Shares	Avg. Exercise Price	Shares	Avg. Exercise Price
Outstanding at beginning of year	180,912	$ 35.55	223,750	$ 33.09	246,995	$ 31.59
Exercised	(33,007)	28.61	(42,588)	22.57	(22,757)	16.80
Expired/canceled	(131)	35.45	(250)	39.91	(488)	35.86
Outstanding at end of year	147,774	37.11	180,912	35.55	223,750	33.09
Exercisable at end of year	147,774	37.11	180,912	35.55	222,054	33.06

The following table summarizes information about stock options outstanding at December 31, 2005 (shares in thousands):

Options Outstanding and Exercisable			
Exercise Price Range	Shares	Avg. Remaining Contractual Life	Avg. Exercise Price
$ 21.78 - 31.70	41,347	2.4 years	$ 28.01
36.18 - 45.22	106,427	4.6 years	40.64
Total	147,774	4.0 years	$ 37.11

14. 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 and paid. All of the punitive damage claims were consolidated in the civil trial that began in 1994. The first judgment from the United States District Court for the District of Alaska in the amount of $5 billion was vacated by the United States Court of Appeals for the Ninth Circuit as being excessive under the Constitution. The second judgment in the amount of $4 billion was vacated by the Ninth Circuit panel without argument and sent back for the District Court to reconsider in light of the recent U.S. Supreme Court decision in *Campbell v. State Farm*. The most recent District Court judgment for punitive damages was for $4.5 billion plus interest and was entered in January 2004. ExxonMobil and the plaintiffs have appealed this decision to the Ninth Circuit. The Corporation has posted a $5.4 billion letter of credit. Oral arguments were held before the Ninth Circuit on January 27, 2006. Management believes that the likelihood of the judgment being upheld is remote. While it is reasonably possible that a liability may have been incurred from the Exxon Valdez grounding, it is not possible to predict the ultimate outcome or to reasonably estimate any such potential liability.

In December 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 in May 2001. In December 2002, the Alabama Supreme Court vacated the $3.5 billion jury verdict. The case was retried and in November 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. In March 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 to the Alabama Supreme Court. 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. In May 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. 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.

In 2001, a Louisiana state court jury awarded compensatory damages of $56 million and punitive damages of $1 billion to a landowner for damage caused by a third party that leased the property from the landowner. The third party provided pipe cleaning and storage services for the Corporation and other entities. The Louisiana Fourth Circuit Court of Appeals reduced the punitive damage award to $112 million in 2005. The Corporation appealed this decision to the Louisiana Supreme Court as it continues to believe that these judgments should be substantially reduced on legal and constitutional grounds. While it is reasonably possible that a liability may have been incurred, 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 2001 that a class of Exxon dealers between March 1983 and August 1994 had been overcharged for gasoline. In June 2003, the Eleventh Circuit Court of Appeals affirmed the judgment and in March 2004, denied a petition for Rehearing En Banc. In October 2004, the U.S. Supreme Court granted review 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. In light of the Supreme Court's decision to grant review of only part of ExxonMobil's appeal, the Corporation took an after-tax charge of $550 million in the third quarter of 2004 reflecting the estimated liability, after considering potential set-offs and defenses for the claims under review by the Supreme Court. In June 2005, the Supreme Court granted the District Court the right to hear the claims of all class members and the Corporation took an after-tax charge of $200 million. Class counsel and ExxonMobil are seeking court approval of a settlement of $1,075 million, pre-tax that would essentially finalize the Corporation's financial obligation in the case; this obligation has been fully accrued. The trial court has preliminarily approved the settlement. Notice has been issued to the class and the final approval hearing will occur in April 2006.

Tax issues for 1986 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

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2005, for $3,893 million, primarily relating to guarantees for notes, loans and performance under contracts. This included $1,020 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 $2,649 million, representing ExxonMobil's share of obligations of certain equity companies.

	Dec. 31, 2005		
	Equity Company Obligations	Other Third-Party Obligations	Total
		(millions of dollars)	
Guarantees of excise taxes/customs duties under reciprocal arrangements	$ —	$ 1,020	$1,020
Other guarantees	2,649	224	2,873
Total	$ 2,649	$ 1,244	$3,893

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			
	2006	2007-2010	2011 and Beyond	Total
		(millions of dollars)		
Unconditional purchase obligations [1]	$569	$1,909	$2,098	$4,576

(1) *Undiscounted obligations of $4,576 million mainly pertain to pipeline throughput agreements and include $2,324 million of obligations to equity companies. The present value of these commitments, excluding imputed interest of $1,248 million, totaled $3,328 million.*

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

15. Annuity Benefits and Other Postretirement Benefits

	Annuity Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2005	2004	2003	2005	2004	2003	2005	2004	2003
	(millions of dollars)								
Components of net benefit cost									
Service cost	$ 330	$ 308	$ 284	$ 382	$ 357	$ 326	$ 70	$ 62	$ 36
Interest cost	611	611	624	834	812	728	301	295	234
Expected return on plan assets	(629)	(618)	(418)	(789)	(684)	(552)	(39)	(36)	(31)
Amortization of actuarial loss/(gain) and prior service cost	274	286	321	424	378	384	204	191	96
Net pension enhancement and curtailment/settlement expense	123	177	204	10	3	37	—	—	—
Net benefit cost	$ 709	$ 764	$1,015	$ 861	$ 866	$ 923	$ 536	$ 512	$ 335
Weighted-average assumptions used to determine net benefit cost for years ended December 31	*(percent)*								
Discount rate	5.75	6.00	6.75	4.9	5.2	5.2	5.75	6.00	6.75
Long-term rate of return on funded assets	9.00	9.00	9.00	7.7	7.7	7.7	9.00	9.00	9.00
Long-term rate of compensation increase	3.50	3.50	3.50	3.8	3.8	3.9	3.50	3.50	3.50

Costs for defined contribution plans were $251 million, $245 million and $253 million in 2005, 2004 and 2003, 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.			
	2005	2004	2005	2004	2005	2004
	(millions of dollars)					
Change in benefit obligation [(1)]						
Benefit obligation at January 1	$10,770	$10,280	$18,704	$16,313	$5,388	$4,960
Service cost	330	308	382	357	70	62
Interest cost	611	611	834	812	301	295
Actuarial loss/(gain)	279	700	1,608	874	(17)	330
Benefits paid	(809)	(1,127)	(1,037)	(1,020)	(431)	(350)
Foreign exchange rate changes	—	—	(1,577)	1,182	15	29
Other	—	(2)	396	186	44	62
Projected benefit obligation at December 31	$11,181	$10,770	$19,310	$18,704	$5,370	$5,388
Accumulated benefit obligation at December 31	$ 9,477	$ 9,193	$17,467	$17,003	$ —	—
Weighted-average assumptions used to determine benefit obligations at December 31	*(percent)*					
Discount rate	5.75	5.75	4.5	4.9	5.75	5.75
Long-term rate of compensation increase	3.50	3.50	3.9	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.

For U.S. plans, the discount rate is determined by constructing a portfolio of high-quality, non-callable bonds with cash flows that match estimated outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using bond portfolios with an average maturity approximating that of the liabilities or spot yield curves, both of which are constructed using high-quality, local-currency-denominated bonds.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.5 percent for 2006 that declines to 2.5 percent by 2011. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $32 million and the postretirement benefit obligation by $352 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $26 million and the postretirement benefit obligation by $299 million.

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 which reduced the year-end 2004 benefit obligation by $383 million and the 2005 net benefit cost by $57 million.

	Annuity Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2005	2004	2005	2004	2005	2004
	(millions of dollars)					
Change in plan assets						
Fair value at January 1	$7,299	$ 7,301	$10,673	$ 9,185	$ 444	$ 412
Actual return on plan assets	626	967	1,871	1,086	30	50
Foreign exchange rate changes	—	—	(860)	691	—	—
Payments directly to participants	134	157	323	303	313	236
Company contribution	—	—	1,055	473	36	34
Benefits paid	(809)	(1,127)	(1,037)	(1,020)	(431)	(350)
Other	—	1	38	(45)	64	62
Fair value at December 31	$7,250	$ 7,299	$12,063	$10,673	$ 456	$ 444

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 2005 compares to an actual rate of return for the U.S. annuity fund over the past decade of 11 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.			
	2005	2004	2005	2004	2005	2004
	(percent)					
Funded benefit plan asset allocation						
Equity securities	75%	75%	68%	69%	75%	76%
Debt securities	25	25	28	29	25	24
Other	—	—	4	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.			
	2005	2004	2005	2004	2005	2004
			(millions of dollars)			
Assets in excess of/(less than) projected benefit obligation						
Balance at December 31 [1]	$(3,931)	$(3,471)	$(7,247)	$(8,031)	$(4,914)	$(4,944)
Unrecognized net transition liability/(asset)	—	—	10	2	—	—
Unrecognized net actuarial loss/(gain)	2,551	2,638	4,847	4,859	1,562	1,696
Unrecognized prior service cost	144	172	491	512	474	567
Net amount recognized	$(1,236)	$ (661)	$(1,899)	$(2,658)	$(2,878)	$(2,681)
Amounts recognized in the consolidated balance sheet consist of:						
Prepaid benefit cost [2]	$ 37	$ 71	$ 715	$ 713	$ —	$ —
Accrued benefit cost [3]	(2,256)	(1,951)	(5,926)	(7,081)	(2,878)	(2,681)
Intangible assets	204	244	388	712	—	—
Equity of minority shareholders	—	—	178	117	—	—
Accumulated other nonowner changes in equity, minimum pension liability adjustment	779	975	2,746	2,881	—	—
Net amount recognized	$(1,236)	$ (661)	$(1,899)	$(2,658)	$(2,878)	$(2,681)

(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.	Gross	Medicare Subsidy Receipt
		(millions of dollars)		
Contributions expected in 2006	$0 –500[1]	$ 700	$ 35	$ —
Benefit payments expected in:				
2006	684	974	383	20
2007	739	988	391	21
2008	784	1,012	399	22
2009	839	1,037	407	22
2010	870	1,075	417	23
2011 - 2015	5,129	6,228	2,161	121

(1) *Amount depends on outcome of pending legislation.*

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.)	
	2005	2004
	(millions of dollars)	
Increase/(decrease) in accumulated other nonowner changes in equity, before tax	$ 331	$ (4)
Deferred income tax (charge)/credit (see note 17, page 75)	(90)	(49)
Increase/(decrease) in accumulated other nonowner changes in equity, after tax (see Consolidated Statement of Shareholders’ Equity, page 50)	$ 241	$ (53)

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.	
	2005	2004	2005	2004
	(millions of dollars)			
For funded pension plans with accumulated benefit obligations in excess of plan assets:				
Projected benefit obligation	$9,816	$9,397	$11,352	$11,552
Accumulated benefit obligation	8,356	8,038	10,480	10,681
Fair value of plan assets	7,198	7,127	8,876	8,128
Accumulated benefit obligation less fair value of plan assets	1,158	911	1,604	2,553
For unfunded plans covered by book reserves:				
Projected benefit obligation	1,343	1,260	4,757	4,827
Accumulated benefit obligation	1,098	1,041	4,211	4,305

16. 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. 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 it's performance; and (c) for which discrete financial information is available.

Earnings after income tax include special items and transfers are at estimated market prices. Special items included in 2005 after-tax earnings are a $1,620 million gain in Non-U.S. Upstream for the restructuring of a Dutch gas equity company, a $390 million gain in Non-U.S. Chemical relating to joint venture litigation, gains of $310 million and $150 million in Non-U.S. Downstream and Non-U.S. Chemical, respectively, for the Sinopec share sale and a charge of $200 million in U.S. Downstream relating to the Allapattah lawsuit provision. U.S. Downstream after-tax earnings in 2004 included a charge of $550 million relating to Allapattah. Upstream 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.

Interest expense includes non-debt related interest expense of $369 million, $529 million and $106 million in 2005, 2004 and 2003, respectively. The increase of $423 million from 2003 to 2004 primarily reflects the interest component of the Allapattah lawsuit provision. The subsequent decrease of $160 million in 2005 reflects a lower interest component for Allapattah.

The Other segment includes corporate and financing activities. The interest revenue amount relates to interest earned on cash deposits and marketable securities.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Upstream U.S.	Upstream Non-U.S.	Downstream U.S.	Downstream Non-U.S.	Chemical U.S.	Chemical Non-U.S.	Other	Corporate Total
				(millions of dollars)				
As of December 31, 2005								
Earnings after income tax	$ 6,200	$18,149	$ 3,911	$ 4,081	$ 1,186	$ 2,757	$ (154)	$ 36,130
Earnings of equity companies included above	1,106	5,084	165	471	53	954	(250)	7,583
Sales and other operating revenue [(1)]	6,730	23,324	91,954	205,726	11,842	19,344	35	358,955
Intersegment revenue	7,230	31,371	9,817	40,255	6,521	5,413	290	—
Depreciation and depletion expense	1,293	5,407	615	1,611	416	410	501	10,253
Interest revenue	—	—	—	—	—	—	946	946
Interest expense	30	32	230	34	4	4	162	496
Income taxes	3,516	15,968	2,139	1,362	447	794	(924)	23,302
Additions to property, plant and equipment	1,763	8,796	662	1,618	218	268	514	13,839
Investments in equity companies	1,470	6,735	420	937	275	2,282	(3)	12,116
Total assets	20,827	66,239	16,110	47,691	7,794	11,702	37,972	208,335
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 [(1)]	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	25	27	431	33	2	1	119	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 [(1)]	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	17	17	8	26	1	—	138	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

Geographic

Sales and other operating revenue [(1)]	2005	2004	2003
		(millions of dollars)	
United States	$110,553	$ 88,382	$ 70,128
Non-U.S.	248,402	202,870	166,926
Total	$358,955	$291,252	$237,054
Significant non-U.S. revenue sources include:			
Japan	$ 28,963	$ 25,485	$ 22,360
Canada	28,842	21,689	17,897
United Kingdom	24,805	22,549	19,946
Germany	21,653	17,649	15,764
Italy	17,160	15,096	13,074
France	14,412	12,231	9,725

(1) *Sales and other operating revenue includes excise taxes of $30,742 million for 2005, $27,263 million for 2004 and $23,855 million for 2003. Includes amounts for purchases/sales contracts with the same counterparty.*

Long-lived assets	2005	2004	2003
		(millions of dollars)	
United States	$ 33,117	$ 33,569	$ 34,585
Non-U.S.	73,893	75,070	70,380
Total	$ 107,010	$ 108,639	$ 104,965
Significant non-U.S. long-lived assets include:			
Canada	$ 12,273	$ 11,806	$ 10,849
United Kingdom	7,757	9,545	9,615
Norway	6,472	7,561	7,047
Nigeria	6,409	4,923	3,833
Japan	4,016	4,784	4,931

Angola	3,803	3,544	2,666
Singapore	2,968	3,089	3,252

17. Income, Excise and Other Taxes

	2005 U.S.	2005 Non-U.S.	2005 Total	2004 U.S.	2004 Non-U.S.	2004 Total	2003 U.S.	2003 Non-U.S.	2003 Total
				(millions of dollars)					
Income taxes									
Federal or non-U.S.									
Current	$ 5,462	$17,052	$22,514	$ 4,410	$12,030	$16,440	$ 1,522	$ 7,426	$ 8,948
Deferred – net	(584)	362	(222)	(1,113)	122	(991)	996	645	1,641
U.S. tax on non-U.S. operations	208	—	208	56	—	56	71	—	71
	5,086	17,414	22,500	3,353	12,152	15,505	2,589	8,071	10,660
State	802	—	802	406	—	406	346	—	346
Total income taxes	5,888	17,414	23,302	3,759	12,152	15,911	2,935	8,071	11,006
Excise taxes	7,072	23,670	30,742	6,833	20,430	27,263	6,323	17,532	23,855
All other taxes and duties									
Other taxes and duties	51	41,503	41,554	26	40,928	40,954	22	37,623	37,645
Included in production and manufacturing expenses	1,182	1,075	2,257	982	951	1,933	976	812	1,788
Included in SG&A expenses	202	558	760	215	503	718	211	463	674
Total other taxes and duties	1,435	43,136	44,571	1,223	42,382	43,605	1,209	38,898	40,107
Total	$14,395	$84,220	$98,615	$11,815	$74,964	$86,779	$10,467	$64,501	$74,968

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 $199 million in 2005, $318 million in 2004, and $124 million in 2003. Income taxes (charged)/credited directly to shareholders' equity were:

	2005	2004	2003
		(millions of dollars)	
Cumulative foreign exchange translation adjustment	$158	$(180)	$(233)
Minimum pension liability adjustment	(90)	(49)	(381)
Gains and losses on stock investments	236	53	(331)
Other components of shareholders' equity	224	183	107

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2005, 2004 and 2003, is as follows:

	2005	2004	2003
		(millions of dollars)	
Earnings before federal and non-U.S. income taxes			
United States	$16,098	$11,067	$ 9,438
Non-U.S.	42,532	29,768	22,182
Total	$58,630	$40,835	$31,620
Theoretical tax	$20,521	$14,292	$11,067
Effect of equity method accounting	(2,654)	(1,736)	(1,531)
Non-U.S. taxes in excess of theoretical U.S. tax	4,719	3,093	1,635
U.S. tax on non-U.S. operations	208	56	71
U.S. tax settlement	—	—	(541)
Other U.S.	(294)	(200)	(41)
Federal and non-U.S. income tax expense	$22,500	$15,505	$10,660
Total effective tax rate	41.4%	40.3%	36.4%

The effective income tax rate includes state income taxes and the Corporation's share of income taxes of equity companies. Equity company taxes totaled $2,226 million in 2005, $1,180 million in 2004, and $983 million in 2003, 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:	2005	2004
	(millions of dollars)	
Depreciation	$17,000	$16,732
Intangible development costs	4,809	4,733
Capitalized interest	2,311	2,279
Other liabilities	2,457	3,295
Total deferred tax liabilities	$26,577	$27,039
Pension and other postretirement benefits	$ (2,654)	$ (2,613)
Tax loss carryforwards	(1,996)	(2,399)
Other assets	(5,091)	(3,761)
Total deferred tax assets	$ (9,741)	$ (8,773)
Asset valuation allowances	566	686
Net deferred tax liabilities	$17,402	$18,952

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	**2005**	**2004**
	(millions of dollars)	
Prepaid taxes and expenses	$ (2,081)	$ (1,221)
Other assets, including intangibles, net	(1,540)	(1,406)
Accounts payable and accrued liabilities	145	487
Deferred income tax liabilities	20,878	21,092
Net deferred tax liabilities	$17,402	$18,952

The Corporation had $41 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 $3,546 million in 2005, $1,340 million in 2004 and $2,300 million in 2003.

Results of Operations	United States	Canada	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(millions of dollars)				
2005 – Revenue								
Sales to third parties	$ 4,842	$3,216	$ 8,383	$ 40	$ 2,357	$ 357	$512	$19,707
Transfers	6,277	3,400	7,040	12,293	3,143	279	182	32,614
	$ 11,119	$6,616	$15,423	$12,333	$ 5,500	$ 636	$694	$52,321
Production costs excluding taxes	1,367	1,265	2,174	840	567	123	105	6,441
Exploration expenses	158	36	64	310	122	164	101	955
Depreciation and depletion	1,181	983	2,133	1,319	666	137	58	6,477
Taxes other than income	738	53	690	1,158	839	2	3	3,483
Related income tax	3,138	1,482	6,572	5,143	1,313	111	159	17,918
Results of producing activities for consolidated subsidiaries	$ 4,537	$2,797	$ 3,790	$ 3,563	$ 1,993	$ 99	$268	$17,047
Proportional interest in results of producing activities of equity companies	$ 1,043	$ —	$ 1,003	$ —	$ 1,009	$ 701	$—	$ 3,756
2004 – Revenue								
Sales to third parties	$ 4,203	$2,460	$ 6,714	$ 29	$ 2,291	$ 74	$480	$16,251
Transfers	5,555	2,680	5,347	7,272	2,770	157	22	23,803
	$ 9,758	$5,140	$12,061	$ 7,301	$ 5,061	$ 231	$502	$40,054
Production costs excluding taxes	1,442	1,085	1,932	719	643	102	82	6,005
Exploration expenses	193	92	112	321	104	188	76	1,086
Depreciation and depletion	1,335	969	2,082	839	702	35	60	6,022
Taxes other than income	550	49	582	722	634	—	3	2,540
Related income tax	2,546	1,015	4,417	2,789	1,103	2	97	11,969
Results of producing activities for consolidated subsidiaries	$ 3,692	$1,930	$ 2,936	$ 1,911	$ 1,875	$ (96)	$184	$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	$ 56	$ 2,368	$ 31	$347	$14,547
Transfers	4,619	2,090	4,397	4,443	2,211	144	17	17,921
	$ 8,876	$4,311	$ 9,664	$ 4,499	$ 4,579	$ 175	$364	$32,468
Production costs excluding taxes	1,435	1,054	1,688	564	594	79	79	5,493
Exploration expenses	257	92	144	217	152	92	54	1,008
Depreciation and depletion	1,456	782	1,833	459	770	33	62	5,395
Taxes other than income	540	39	658	528	448	—	3	2,216
Related income tax	2,017	738	2,902	1,496	1,090	11	39	8,293
Results of producing activities for consolidated subsidiaries	$ 3,171	$1,606	$ 2,439	$ 1,235	$ 1,525	$ (40)	$127	$10,063
Proportional interest in results of producing activities of equity companies	$ 584	$ —	$ 836	$ —	$ 424	$ 295	$—	$ 2,139

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 81 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 82 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	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
During 2005								
Average sales prices								
Crude oil and NGL, per barrel	$46.11	$38.38	$50.32	$51.21	$ 52.89	$51.65	$40.67	$48.23
Natural gas, per thousand cubic feet	7.30	7.43	5.64	—	4.16	1.35	1.20	5.96
Average production costs, per barrel (1)	5.56	7.76	5.95	3.46	3.85	9.49	4.54	5.36
During 2004								
Average sales prices								
Crude oil and NGL, per barrel	$34.84	$30.26	$35.71	$35.04	$ 39.04	$34.99	$26.89	$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 (1)	5.05	6.47	4.95	3.44	3.72	16.62	3.23	4.78
During 2003								
Average sales prices								
Crude oil and NGL, per barrel	$25.74	$23.84	$27.15	$28.29	$ 29.01	$27.81	$20.47	$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 (1)	4.48	6.17	4.34	3.49	2.91	12.80	3.41	4.31

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

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

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $5,541 million less at year-end 2005 and $4,769 million less at year-end 2004 than the amounts reported as investments in property, plant and equipment for the Upstream in note 8, page 60. 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.

Capitalized Costs	United States	Canada	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(millions of dollars)				
As of December 31, 2005								
Property (acreage) costs – Proved	$ 3,407	$ 3,336	$ 210	$ 184	$ 954	$ 460	$ 209	$ 8,760
– Unproved	587	266	29	544	858	99	227	2,610
Total property costs	$ 3,994	$ 3,602	$ 239	$ 728	$ 1,812	$ 559	$ 436	$ 11,370
Producing assets	34,306	11,261	39,355	11,818	15,024	857	1,006	113,627
Support facilities	620	199	478	410	1,158	217	51	3,133
Incomplete construction	1,862	789	1,073	4,903	751	3,109	154	12,641
Total capitalized costs	$40,782	$15,851	$41,145	$17,859	$ 18,745	$4,742	$1,647	$140,771
Accumulated depreciation and depletion	26,071	9,573	28,899	5,115	13,070	330	437	83,495
Net capitalized costs for consolidated subsidiaries	$14,711	$ 6,278	$12,246	$12,744	$ 5,675	$4,412	$1,210	$ 57,276
Proportional interest of net capitalized costs of equity companies	$ 1,386	$ —	$ 1,310	$ —	$ 1,043	$2,746	$ —	$ 6,485
As of December 31, 2004								
Property (acreage) costs – Proved	$ 3,739	$ 3,414	$ 235	$ 253	$ 998	$ 314	$ 209	$ 9,162
– Unproved	623	244	35	552	855	118	216	2,643
Total property costs	$ 4,362	$ 3,658	$ 270	$ 805	$ 1,853	$ 432	$ 425	$ 11,805
Producing assets	34,875	11,318	43,899	8,537	15,025	231	1,001	114,886
Support facilities	617	119	530	383	1,081	93	44	2,867
Incomplete construction	1,637	419	1,136	4,782	897	2,346	173	11,390
Total capitalized costs	$41,491	$15,514	$45,835	$14,507	$ 18,856	$3,102	$1,643	$140,948
Accumulated depreciation and depletion	26,508	8,905	30,943	3,801	12,948	193	406	83,704
Net capitalized costs for consolidated subsidiaries	$14,983	$ 6,609	$14,892	$10,706	$ 5,908	$2,909	$1,237	$ 57,244
Proportional interest of net capitalized costs of equity companies	$ 1,234	$ —	$ 1,277	$ —	$ 767	$2,427	$ —	$ 5,705

Oil and Gas Exploration and Production Costs *(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 2005 were $10,784 million, up $1,767 million from 2004, due primarily to higher development and property acquisition costs. 2004 costs were $9,017 million, down $819 million from 2003, due primarily to lower development costs.

Costs incurred in property acquisitions, exploration and development activities	United States	Canada	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(millions of dollars)				
During 2005								
Property acquisition costs – Proved	$ —	$ —	$ —	$ —	$ —	$ 174	$—	$ 174
– Unproved	11	6	—	53	41	156	12	279
Exploration costs	286	62	133	507	171	159	59	1,377
Development costs	1,426	624	1,302	3,189	541	1,774	98	8,954
Total costs incurred for consolidated subsidiaries	$1,723	$ 692	$1,435	$3,749	$ 753	$2,263	$169	$10,784
Proportional interest of costs incurred of equity companies	$ 269	$ —	$ 210	$ —	$ 319	$ 384	$—	$ 1,182
During 2004								
Property acquisition costs – Proved	$ —	$ —	$ —	$ 68	$ —	$ 25	$—	$ 93
– Unproved	14	1	—	24	2	—	—	41
Exploration costs	232	68	123	382	110	189	86	1,190
Development costs	1,427	694	1,232	2,788	494	985	73	7,693
Total costs incurred for consolidated subsidiaries	$1,673	$ 763	$1,355	$3,262	$ 606	$1,199	$159	$ 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	264	144	170	67	1,152
Development costs	1,636	644	1,755	3,117	731	729	27	8,639
Total costs incurred for consolidated subsidiaries	$1,905	$ 753	$1,912	$3,398	$ 875	$ 899	$ 94	$ 9,836
Proportional interest of costs incurred of equity companies	$ 145	$ —	$ 231	$ —	$ 146	$ 289	$—	$ 811

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

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2003, 2004 and 2005.

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.

Based on regulatory guidance, the Corporation began reporting proved reserves in 2004 on the basis of December 31 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 are 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.

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, or (3) changes to underlying price assumptions used in the determination of reserves. 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 81 to 83, 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 2005 that were associated with production sharing contract arrangements was 17 percent of liquids, 10 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 86 due to volumes consumed or flared and inventory changes.

Crude Oil and Natural Gas Liquids	United States	Canada (1)	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(millions of barrels)				
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2003	2,909	1,285	1,333	2,626	592	353	527	9,625
Revisions	31	14	50	176	68	—	2	341
Purchases	1	—	—	—	—	—	—	1
Sales	(14)	—	(2)	—	—	—	—	(16)
Improved recovery	16	3	1	66	—	—	—	86
Extensions and discoveries	27	6	10	36	49	503	—	631
Production	(178)	(114)	(208)	(162)	(94)	(6)	(17)	(779)
December 31, 2003	2,792	1,194	1,184	2,742	615	850	512	9,889
Revisions	(46)	4	35	(39)	7	97	(14)	44
Purchases	—	—	—	10	—	—	—	10
Sales	(113)	(3)	—	—	(16)	—	—	(132)
Improved recovery	5	—	—	—	—	—	—	5
Extensions and discoveries	15	4	3	150	2	—	—	174
Production	(161)	(108)	(210)	(209)	(81)	(6)	(20)	(795)
Total before 2004 year-end price/cost revisions	2,492	1,091	1,012	2,654	527	941	478	9,195
Year-end price/cost revisions	101	(464)	2	(210)	(12)	(217)	—	(800)
December 31, 2004	2,593	627	1,014	2,444	515	724	478	8,395
Remove 2004 year-end price/cost revisions	(101)	464	(2)	210	12	217	—	800
Total before 2004 year-end price/cost revisions	2,492	1,091	1,012	2,654	527	941	478	9,195
Revisions	(235)	2	11	(53)	106	(96)	(2)	(267)
Purchases	—	—	—	—	—	113	—	113
Sales	(96)	(42)	(1)	—	(11)	(70)	(7)	(227)
Improved recovery	2	—	3	—	—	—	—	5
Extensions and discoveries	6	19	47	170	—	—	—	242
Production	(136)	(107)	(197)	(244)	(67)	(13)	(18)	(782)
Total before 2005 year-end price/cost revisions	2,033	963	875	2,527	555	875	451	8,279
Year-end price/cost revisions	80	(131)	8	(215)	(40)	(168)	—	(466)
December 31, 2005	2,113	832	883	2,312	515	707	451	7,813
Proportional interest in proved reserves of equity companies								
End of year 2003	426	—	20	—	767	973	—	2,186
End of year 2004 (2)	402	—	17	—	1,169	911	—	2,499
End of year 2005 (2)	413	—	11	—	1,381	873	—	2,678
Proved developed reserves, included above, as of December 31, 2003								
Consolidated subsidiaries	2,348	750	805	1,107	489	33	132	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	1,117	403	34	129	5,211
Equity companies	347	—	15	—	642	600	—	1,604
Proved developed reserves, included above, as of December 31, 2005								
Consolidated subsidiaries	1,680	607	656	1,218	464	55	227	4,907
Equity companies	326	—	9	—	725	574	—	1,634

(1) *Includes total proved reserves attributable to Imperial Oil Limited of 889 million barrels in 2003, 347 million barrels in 2004 and 634 million barrels in 2005, as well as proved developed reserves of 519 million barrels in 2003, 343 million barrels in 2004 and 449 million barrels in 2005, in which there is a 30.4 percent minority interest.*

(2) *Year-end equity company total reserves of 2,499 million barrels in 2004 and 2,678 million barrels in 2005 included a negative revision of 62 million barrels in 2004 and no revisions in 2005 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	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(billions of cubic feet)				
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2003	12,062	2,882	10,508	436	7,775	231	687	34,581
Revisions	124	(199)	411	157	19	—	(2)	510
Purchases	10	—	—	—	—	—	—	10
Sales	(90)	—	(3)	—	—	—	—	(93)
Improved recovery	9	1	—	—	—	—	—	10
Extensions and discoveries	156	45	333	1	872	238	—	1,645
Production	(999)	(388)	(1,103)	(11)	(727)	—	(40)	(3,268)
December 31, 2003	11,272	2,341	10,146	583	7,939	469	645	33,395
Revisions	31	19	(65)	165	(450)	47	164	(89)
Purchases	—	—	—	9	—	—	—	9
Sales	(142)	(18)	(16)	—	(301)	—	—	(477)
Improved recovery	2	—	31	—	—	—	—	33
Extensions and discoveries	121	36	39	39	44	—	—	279
Production	(846)	(399)	(1,092)	(25)	(633)	—	(40)	(3,035)
Total before 2004 year-end price/cost revisions	10,438	1,979	9,043	771	6,599	516	769	30,115
Year-end price/cost revisions	1,891	(96)	142	—	(208)	(1)	—	1,728
December 31, 2004	12,329	1,883	9,185	771	6,391	515	769	31,843
Remove 2004 year-end price/cost revisions	(1,891)	96	(142)	—	208	1	—	(1,728)
Total before 2004 year-end price/cost revisions	10,438	1,979	9,043	771	6,599	516	769	30,115
Revisions	1,369	128	221	35	1,879	(8)	(112)	3,512
Purchases	—	—	—	—	—	53	—	53
Sales	(105)	(23)	(73)	—	—	(26)	(2)	(229)
Improved recovery	—	—	—	—	—	—	—	—
Extensions and discoveries	288	27	116	57	33	315	—	836
Production	(764)	(376)	(1,072)	(22)	(546)	(3)	(36)	(2,819)
Total before 2005 year-end price/cost revisions	11,226	1,735	8,235	841	7,965	847	619	31,468
Year-end price/cost revisions	2,466	(30)	163	—	(686)	(26)	—	1,887
December 31, 2005	13,692	1,705	8,398	841	7,279	821	619	33,355
Proportional interest in proved reserves of equity companies								
End of year 2003	152	—	13,703	—	6,055	1,464	—	21,374
End of year 2004 (2)	140	—	13,557	—	13,455	1,367	—	28,519
End of year 2005 (2)	136	—	13,024	—	19,119	1,273	—	33,552

(1) *Includes total proved reserves attributable to Imperial Oil Limited of 1,023 billion cubic feet in 2003, 791 billion cubic feet in 2004 and 747 billion cubic feet in 2005, in which there is a 30.4 percent minority interest.*

(2) *Year-end equity company total reserves of 28,519 billion cubic feet in 2004 and 33,552 billion cubic feet in 2005 included a positive revision of 694 billion cubic feet in 2004 and a positive revision of 1,053 billion cubic feet in 2005 due to the use of year-end prices and costs.*

Natural Gas *(continued)*	United States	Canada (1)	Europe	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(billions of cubic feet)				
Proved developed reserves, included above, as of December 31, 2003								
Consolidated subsidiaries	9,513	1,962	7,196	155	5,785	3	328	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	279	4,440	4	279	22,859
Equity companies	120	—	9,805	—	4,578	837	—	15,340
Proved developed reserves, included above, as of December 31, 2005								
Consolidated subsidiaries	10,386	1,527	6,332	376	6,067	227	313	25,228
Equity companies	113	—	10,226	—	7,276	835	—	18,450

(1) *Includes proved developed reserves attributable to Imperial Oil Limited of 859 billion cubic feet in 2003, 704 billion cubic feet in 2004 and 643 billion cubic feet in 2005, in which there is a 30.4 percent minority interest.*

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 84.

Tar Sands Reserves	Canada *(millions of barrels)*
At December 31, 2003	781
At December 31, 2004	757
At December 31, 2005	738

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	Africa	Asia Pacific/ Middle East	Russia/ Caspian	Other	Total
				(millions of dollars)				
Consolidated subsidiaries								
As of December 31, 2003								
Future cash inflows from sales of oil and gas	$127,459	$ 35,637	$ 71,937	$ 76,969	$ 34,597	$21,582	$10,346	$378,527
Future production costs	26,777	11,451	16,090	15,017	9,479	3,450	2,400	84,664
Future development costs	4,537	3,659	6,966	7,576	2,812	4,161	630	30,341
Future income tax expenses	38,690	7,835	25,080	29,808	9,241	3,428	2,282	116,364
Future net cash flows	$ 57,455	$ 12,692	$ 23,801	$ 24,568	$ 13,065	$10,543	$ 5,034	$147,158
Effect of discounting net cash flows at 10%	31,107	4,688	7,970	10,868	4,927	7,446	3,215	70,221
Discounted future net cash flows	$ 26,348	$ 8,004	$ 15,831	$ 13,700	$ 8,138	$ 3,097	$ 1,819	$ 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	$ 87,687	$ 31,795	$25,203	$11,708	$402,360
Future production costs	30,096	5,686	17,847	17,929	9,499	3,465	2,035	86,557
Future development costs	6,181	2,743	7,670	7,822	2,798	4,273	593	32,080
Future income tax expenses	42,928	5,662	28,883	33,945	7,466	4,203	2,944	126,031
Future net cash flows	$ 62,056	$ 10,917	$ 25,298	$ 27,991	$ 12,032	$13,262	$ 6,136	$157,692
Effect of discounting net cash flows at 10%	36,078	3,598	8,485	11,287	4,459	8,797	3,904	76,608
Discounted future net cash flows	$ 25,978	$ 7,319	$ 16,813	$ 16,704	$ 7,573	$ 4,465	$ 2,232	$ 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
Consolidated subsidiaries								
As of December 31, 2005								
Future cash inflows from sales of oil and gas	$200,119	$ 37,309	$107,127	$127,584	$ 44,411	$35,757	$17,644	$569,951
Future production costs	34,100	12,343	19,958	21,856	12,515	5,324	2,117	108,213
Future development costs	8,935	2,782	8,552	12,464	2,651	4,000	780	40,164
Future income tax expenses	67,581	7,606	47,999	51,610	13,151	6,608	4,737	199,292
Future net cash flows	$ 89,503	$ 14,578	$ 30,618	$ 41,654	$ 16,094	$19,825	$10,010	$222,282
Effect of discounting net cash flows at 10%	53,919	4,136	9,988	15,337	6,800	12,379	6,505	109,064
Discounted future net cash flows	$ 35,584	$ 10,442	$ 20,630	$ 26,317	$ 9,294	$ 7,446	$ 3,505	$113,218
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 7,000	$ —	$ 11,043	$ —	$ 25,311	$ 7,735	$ —	$ 51,089

(1) *Includes discounted future net cash flows attributable to Imperial Oil Limited of $3,667 million in 2003, $2,773 million in 2004 and $3,723 million in 2005, in which there is a 30.4 percent minority interest.*

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

Consolidated Subsidiaries	2005	2004	2003
		(millions of dollars)	
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	$ 4,619	$ 588	$ 4,431
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	(42,606)	(31,726)	(25,012)
Development costs incurred during the year	8,617	7,660	8,350
Net change in prices, lifting and development costs	85,049	21,267	4,014
Revisions of previous reserves estimates	9,050	(766)	2,234
Accretion of discount	9,021	10,645	10,513
Net change in income taxes	(41,616)	(3,521)	(2,975)
Total change in the standardized measure during the year	$ 32,134	$ 4,147	$ 1,555

OPERATING SUMMARY (unaudited)

	2005	2004	2003	2002	2001
	(thousands of barrels daily)				
Production of crude oil and natural gas liquids					
Net production					
United States	477	557	610	681	712
Canada	346	355	363	349	331
Europe	546	583	579	592	653
Africa	666	572	442	349	342
Asia Pacific/Middle East	332	360	386	387	382
Russia/Caspian	107	91	88	91	86
Other Non-U.S.	49	53	48	47	36
Worldwide	2,523	2,571	2,516	2,496	2,542
	(millions of cubic feet daily)				
Natural gas production available for sale					
Net production					
United States	1,739	1,947	2,246	2,375	2,598
Canada	918	972	943	1,024	1,006
Europe	4,315	4,614	4,498	4,463	4,595
Asia Pacific/Middle East	2,114	2,161	2,258	2,427	1,901
Russia/Caspian	77	73	73	77	65
Other Non-U.S.	88	97	101	86	114
Worldwide	9,251	9,864	10,119	10,452	10,279
	(thousands of oil-equivalent barrels daily)				
Oil-equivalent production [(1)]	4,065	4,215	4,203	4,238	4,255
	(thousands of barrels daily)				
Refinery throughput					
United States	1,794	1,850	1,806	1,834	1,811
Canada	466	468	450	447	449
Europe	1,672	1,663	1,566	1,539	1,563
Asia Pacific	1,490	1,423	1,390	1,379	1,436
Other Non-U.S.	301	309	298	244	283
Worldwide	5,723	5,713	5,510	5,443	5,542
Petroleum product sales					
United States	2,915	2,872	2,729	2,731	2,751
Canada	620	615	602	593	585
Europe	2,115	2,139	2,061	2,042	2,079
Asia Pacific and other Eastern Hemisphere	2,128	2,080	2,075	1,889	2,024
Latin America	479	504	490	502	532
Worldwide	8,257	8,210	7,957	7,757	7,971
Gasoline, naphthas	3,274	3,301	3,238	3,176	3,165
Heating oils, kerosene, diesel oils	2,560	2,517	2,432	2,292	2,389
Aviation fuels	700	698	662	691	721
Heavy fuels	711	659	638	604	668
Specialty petroleum products	1,012	1,035	987	994	1,028
Worldwide	8,257	8,210	7,957	7,757	7,971
	(thousands of metric tons)				
Chemical prime product sales					
United States	10,369	11,521	10,740	11,386	11,078
Non-U.S.	16,408	16,267	15,827	15,220	14,702
Worldwide	26,777	27,788	26,567	26,606	25,780

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.*

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/ REX W. TILLERSON

(Rex W. Tillerson,
Chairman of the Board)

Dated February 28, 2006

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints William M. Colton, Richard E. Gutman and Robert E. Harayda, 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/ REX W. TILLERSON (Rex W. Tillerson)	Chairman of the Board (Principal Executive Officer)	February 28, 2006
/s/ MICHAEL J. BOSKIN (Michael J. Boskin)	Director	February 28, 2006
/s/ WILLIAM W. GEORGE (William W. George)	Director	February 28, 2006

/s/ JAMES R. HOUGHTON (James R. Houghton)	Director	February 28, 2006
/s/ WILLIAM R. HOWELL (William R. Howell)	Director	February 28, 2006
/s/ REATHA CLARK KING (Reatha Clark King)	Director	February 28, 2006
/s/ PHILIP E. LIPPINCOTT (Philip E. Lippincott)	Director	February 28, 2006
/s/ HENRY A. MCKINNELL, JR. (Henry A. McKinnell, Jr.)	Director	February 28, 2006
/s/ MARILYN CARLSON NELSON (Marilyn Carlson Nelson)	Director	February 28, 2006
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director	February 28, 2006
/s/ WALTER V. SHIPLEY (Walter V. Shipley)	Director	February 28, 2006
/s/ J. STEPHEN SIMON (J. Stephen Simon)	Director	February 28, 2006
/s/ DONALD D. HUMPHREYS (Donald D. Humphreys)	Treasurer (Principal Financial Officer)	February 28, 2006
/s/ PATRICK T. MULVA (Patrick T. Mulva)	Controller (Principal Accounting Officer)	February 28, 2006

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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 (incorporated by reference to Exhibit 10(iii)(a.2) to the registrant's Annual Report on Form 10-K for 2004).*
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 December 1, 2005).*
10(iii)(b.1).	Short Term Incentive Program, as amended (incorporated 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 December 1, 2005).*
10(iii)(c.1).	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the registrant's Annual Report on Form 10-K for 2004).*
10(iii)(c.2).	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the registrant's Annual Report on Form 10-K for 2004).*
10(iii)(c.3).	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the registrant's Annual Report on Form 10-K for 2004).*
10(iii)(d).	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the registrant's Annual Report on Form 10-K for 2004).*
10(iii)(e).	Agreement dated December 16, 2005, between Exxon Mobil Corporation and L. R. Raymond (incorporated by reference to Exhibit 99.1 to the registrant's Report on Form 8-K on December 16, 2005).*
10(iii)(f.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)(f.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)(f.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.4).	Standing resolution for non-employee director cash fees dated September 27, 2000 (incorporated by reference to Exhibit 10(iii)(f.1) to the registrant's Annual Report on Form 10-K for 2004).*

INDEX TO EXHIBITS—(continued)

10(iii)(f.5).	2001 Nonemployee Directors' Deferred Compensation Plan.*
10(iii)(g.1).	1995 Mobil Incentive Compensation and Stock Ownership Plan.*
10(iii)(g.2).	Form of stock option granted to Mobil executive officers (incorporated by reference to Exhibit 10(iii)(g.2) to the registrant's Annual Report on Form 10-K for 2004).*
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 Financial Officer.
31.3	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting 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 Financial Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.

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* 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.

EXXON MOBIL CORPORATION

2001 NONEMPLOYEE DIRECTORS' DEFERRED COMPENSATION PLAN

(as adopted effective January 1, 2001)

1. Purpose

The purpose of the Plan is to provide nonemployee directors of the Corporation with an opportunity to defer compensation as a director.

2. Effective Date; Transition

(a) This Plan shall become effective on the Effective Date.

(b) For incumbent directors and directors elected after the Effective Date, this Plan replaces the Prior Plan. Accounts of incumbent directors under the Prior Plan shall, as of the Effective Date, be transferred to this Plan with the account balance credited as deferred cash or, to the extent the incumbent director elects reallocation under Section 6(e), deferred stock units. Deferral elections made by an incumbent director under the Prior Plan shall remain in effect for purposes of this Plan, subject to the participant's ability to make a prospective change under Section 5(c)(3) or a one-time reallocation under Section 6(e).

(c) Retired directors shall not be entitled to participate in this Plan. Accounts of retired directors under the Prior Plan shall remain subject to the terms and conditions of the Prior Plan.

3. Definitions

In this Plan, the following definitions apply:

"Account" means the account maintained by the Corporation for deferred cash and deferred stock units credited under Section 6.

"Administrator" means the Secretary of the Corporation.

"Board" means the Board of Directors of the Corporation.

"Compensation" means the cash retainer payable to a nonemployee director for service on the Board, for service as member of any Board committee, and for service as chairman of any Board committee, together with other cash fees, if any, payable to a nonemployee director in that capacity for attending meetings or otherwise for service on the Board or any Board committee. Grants of restricted stock and reimbursement of expenses do not constitute compensation for purposes of this Plan.

"Corporation" means Exxon Mobil Corporation, a New Jersey corporation, and its successors.

"Deferred cash" means a credit to a participant's account under Section 6(b) that represents the right to receive a cash payment equal to the credited amount plus deemed interest on settlement of the account.

"Deferred stock unit" means a credit to a participant's account under Section 6(c) that represents the right to receive a cash payment equal to the fair market value of one share on settlement of the account.

"Effective Date" means January 1, 2001.

"Fair market value" means, for any date, the average of the high and low sales prices for shares as reported on the Consolidated Tape during the New York Stock Exchange regular session on such date.

"Incumbent director" means a nonemployee director who holds office on the Effective Date.

"Nonemployee director" means a member of the Board who is not also an employee of the Corporation or any affiliate of the Corporation.

"Participant" means each nonemployee director who elects to defer compensation under this Plan.

"Plan" means this Exxon Mobil Corporation 2001 Nonemployee Directors' Deferred Compensation Plan, as it may be amended from time to time.

"Prior Plan" means the Exxon Corporation Plan for Deferral of Non-employee Director Compensation and Fees originally adopted by the Board effective May 15, 1980.

"Retired director" means a participant in the Prior Plan who does not hold office on the Effective Date.

"Share" means a share of common stock of the Corporation.

"Term of office" means, for any nonemployee director, each period beginning with the director's election to office and continuing until the next annual meeting of shareholders and until the director is reelected to office or his or her successor shall have been elected and qualified.

4. Administration

The Board and, subject to the oversight of the Board, the Administrator shall have authority to administer the Plan, including conclusive authority to construe and interpret the Plan, to establish rules, policies, procedures, forms, and notices for use in carrying out the Plan, and to make all other determinations necessary or desirable for administration of the Plan.

5. Election to Defer Compensation

(a) Amount of Deferral. A nonemployee director may elect to defer receipt of all or a specified portion of the compensation otherwise thereafter payable to such director.

(b) Manner of Electing Deferral. An election to defer compensation shall be made by giving written notice to the Administrator in the form approved by the Administrator. Such notice shall include:

(1) the percentage of compensation to be deferred,

(2) an election for the deferred compensation to be credited as deferred cash and/or as deferred stock units,

(3) an election for the account to be settled in either a lump-sum payment or in a specified number of annual installments (not to exceed five), and

(4) the date of the lump-sum payment or the first installment payment in settlement of the account (which shall not be earlier than January 15 of the year following the year in which service as a nonemployee director terminates nor later than January 15 first following the participant's 72nd birthday, or such other date as may be approved by the Administrator.)

(c) Time of Election; Effectiveness; Change of Election.

(1) An election to defer compensation for a term of office shall be made by a nonemployee director at, or prior to, the time of election and prior to the right to receive any compensation for such term of office.

(2) An election shall continue in effect until the end of the participant's service as a nonemployee director or until the

effectiveness of a change in the nonemployee director's deferral election, as provided in clause (3) below, whichever occurs first.

(3) A nonemployee director may change a deferral election by giving written notice to the Administrator, *provided* that, except for the one-time reallocation permitted under Section 6(e), a change shall only be effective prospectively for terms of office commencing at or after the time of such notice.

6. Deferred Compensation Account

(a) Establishment of Account. The Corporation will maintain an account for each participant. Accounts under this Plan shall be unfunded and shall represent only an unsecured claim against the general assets of the Corporation.

(b) Deferred Cash. If a participant elects to defer compensation in the form of deferred cash, the amount so deferred will be credited to the participant's account on the date such compensation would otherwise have been payable absent the election to defer. In addition, at the end of each calendar month the deferred cash credits in the account shall be increased by an amount equal to deemed interest, at such reasonable rate per annum as may be determined from time to time by the Administrator, upon the average daily balance of deferred cash in the account during such month.

(c) Deferred Stock Units. If a participant elects to defer compensation in the form of deferred stock units, a number of units will be credited to the participant's account, at the time such compensation would otherwise have been payable absent the election to defer, equal to (i) the otherwise payable amount divided by (ii) the fair market value of a share on the last trading day preceding the credit date. In addition, on each date on which a cash dividend is payable on the shares, the participant's account shall be credited with a number of units equal to (i) the per share cash dividend times the number of deferred stock units then credited to the account, divided by (ii) the fair market value of a share on the last trading day preceding the dividend payment date. Accounts shall be credited with fractional deferred stock units, rounded to the third decimal place.

(d) Adjustments. In case of a stock split, stock dividend, or other relevant change in capitalization, the number of deferred stock units credited to a participant's account shall be adjusted in such manner as the Administrator deems appropriate.

(e) One-time Reallocation to Deferred Stock Units.

(1) Incumbent directors who were participants in the Prior Plan shall have a one-time right to reallocate all or a portion of their account balance to deferred stock units. Such participants may elect reallocation by giving written notice to the Administrator in the form approved by the Administrator.

(2) A reallocation notice under this Section must be received by the Administrator on or before the date of the Corporation's 2001 Annual Meeting of Shareholders and shall include:

(A) the date as of which the reallocation is to be made, which must be (i) on or after the Effective Date, (ii) on or after the date the notice is received, and (iii) no later than the date of the Corporation's 2001 Annual Meeting of Shareholders;

(B) the percentage of the participant's credited account balance to be reallocated to deferred stock units; and

(C) an election for deferred compensation from and after the reallocation date to be credited as deferred cash and/or as deferred stock units, *provided* that the participant shall not be entitled to change the amount of compensation deferred for the current term of office.

(3) If a participant elects to reallocate, on the date specified in the reallocation notice the specified percentage of the account's deferred cash balance, including deemed interest credited through the most recent month end in accordance with Section 6(b), shall be debited from deferred cash and the account shall be credited with a number of deferred stock units equal to (i) the reallocated amount divided by (ii) the fair market value of a share on the last trading day preceding the reallocation date.

(4) Participants shall have no right to have amounts credited as deferred stock units in their accounts reallocated or converted to deferred cash. Except for the one time reallocation right provided above, participants shall have no right to have amounts credited as deferred cash in their accounts reallocated or converted to deferred stock units.

7. Valuation

The value of an account as of any date on which a settlement payment is to be made under Section 8 shall be the sum of (a) the amount of deferred cash then credited to the account, with deemed interest credited through the most recent month end in accordance with Section 6(b), plus (b) an amount equal to the number of deferred stock units then credited to the account times the fair market value of a share on the last trading day preceding the payment date.

8. Settlement

(a) Lump Sum. If a participant elects lump sum settlement, an amount of cash equal to the value of the account determined in accordance with Section 7 shall be paid to the participant on January 15 of the year selected as provided in Section 5(b).

(b) Installment Payments. If a participant elects settlement in installments, an amount of cash determined as hereafter provided shall be paid to the participant on January 15 of each year of the installment payment period selected as provided in Section 5(b). The amount of each installment shall be equal to (i) the value of the account as of the payment date for such installment, determined in accordance with Section 7, divided by (ii) the number of unpaid installments. Each installment payment shall be debited to the deferred cash and deferred stock units in a participant's account on a pro-rata basis.

(c) Payment on Death. Notwithstanding a participant's settlement election, in the event of a participant's death an amount of cash equal to the remaining value of the account determined as provided in Section 7 shall be paid in a single payment to the participant's estate or permitted designated beneficiary as soon as practicable.

(e) No early withdrawal. No withdrawal may be made from a participant's account except as provided in this Section 8.

(f) Cash settlement only. Settlement of accounts under this Plan shall be made only in cash.

9. Beneficiary Designation

Participants may designate a beneficiary to be paid any amounts remaining unpaid under this Plan on the death of the participant, *provided* that such designation will only be given effect if the designation is expressly authorized as a non-testamentary transfer under applicable laws of descent and distribution as determined by the Administrator.

Beneficiary designations shall be subject to such forms, requirements and procedures as the Administrator may establish from time to time.

10. Non-Assignability

The right of a participant to receive any unpaid portion of the participant's account may not be assigned or transferred except by will or the laws of descent and distribution (including permitted beneficiary designations under Section 9), and may not be pledged or encumbered or be subject to attachment, execution, or levy of any kind.

11. Amendment and Termination

This Plan may be amended, modified or terminated by the Board at any time, *provided* that no such amendment, modification or termination shall, without the consent of a participant, adversely affect such participant's rights with respect to amounts accrued in the participant's account.

12. Governing Law

This Plan and all actions taken under it shall be governed by the laws of the State of New York, without reference to conflict of law principles.

13. Severability

If any provision of this Plan shall be deemed illegal or invalid for any reason, such illegality or invalidity shall not affect the remaining provisions of the Plan but shall be fully severable.

14. Compliance

The Administrator is authorized to take such steps as may be necessary including, without limitation, delaying effectiveness of a participant's election or delaying settlement of an account, in order to ensure that this Plan and all actions taken under it comply with any law, regulation, or listing requirement which the Administrator deems applicable or desirable, including the exemption provided by Rule 16b-3 under the Securities Exchange Act of 1934.

1995 MOBIL INCENTIVE COMPENSATION AND STOCK OWNERSHIP PLAN

ARTICLE I—PURPOSE OF THE PLAN

The purpose of the Mobil Incentive Compensation and Stock Ownership Plan is to promote the creation of shareholder value by encouraging, recognizing and rewarding sustained outstanding corporate, division, business unit and individual performance by key Employees of Mobil Corporation and Affiliated Corporations who are largely responsible for the management, growth and protection of the business. The Plan in addition provides part of a competitive total compensation package to attract and retain key Employees.

The components of the Plan include the Short-Term Incentive Program, the Long-Term Incentive Program and the Stock Ownership Program. The purpose of the Short-Term Incentive Program is to base a portion of key Employees' total annual compensation on the performance of the Corporation compared to the performance of other companies selected by the Committee, with the intention that the key Employees will receive total compensation that is above the average for comparable positions paid by such other companies when the Corporation's comparative performance is above average; total compensation that is equal to the average for comparable positions paid by these companies when the Corporation's comparative performance is average; and total compensation that is below the average for comparable positions when the Corporation's comparative performance is below average. The Long-Term Incentive Program provides rewards, based on the performance of the Corporation over a longer term, to those key Employees who have the potential to contribute significantly to the long-term growth and success of the Corporation. These awards are denominated in hypothetical stock or in the form of Restricted Stock, which serves to align the interests of these key Employees with the interests of shareholders. The purpose of the Stock Ownership Program is to provide long- term incentive, designed to encourage Stock ownership by key Employees, thereby directly aligning their financial interests with those of shareholders. Key Employees receive Stock Options, which provide them an opportunity to increase their ownership of Stock, and the Committee is expected to develop guidelines to encourage key Employees to take advantage of the program to acquire and hold Stock.

ARTICLE II—DEFINITIONS

"Adjusted Net Income" with respect to any fiscal year of the Corporation means the amount reported as net income in the Income Statement for such year, adjusted to exclude any of the following items:

(a) extraordinary items (as described in Accounting Principles Board Opinion No. 30);

(b) gains or losses on the disposition of discontinued operations of a segment of the business; and

(c) the cumulative effect of changes in accounting principles.

"Affiliated Corporation" means any stock corporation of which a majority of the voting common or capital stock is owned directly or indirectly by the Corporation.

"Allotment" means a number of Stock Equivalents granted pursuant to Section 5.3(a).

"Allotment Supplement" means a number of Stock Equivalents credited with respect to an Allotment pursuant to Section 5.3(b).

"Authorized Share Pool" for any calendar year during any part of which this Plan is in effect means nine tenths of one percent (0.9%) of the total issued and outstanding shares of Stock as of December 31 of the preceding year, cumulative from the effective date of the Plan, subject to adjustment pursuant to Article IX.

"Award" means a Short-Term Incentive Award or a Long-Term Incentive Award granted under Article V or an Option granted under Article VI. Awards granted that are to be paid upon full satisfaction of any applicable conditions are provisional Awards and are forfeitable until such conditions are satisfied. An Award is non-forfeitable if the only condition to its payment is passage of time.

“Award Date” means the date an Award is granted.

“Board” means the Board of Directors of the Corporation.

“Chief Executive Officer” means the Employee of the Corporation acting in such capacity.

“Code” means the Internal Revenue Code of 1986, as amended from time to time. Reference to a specific provision of the Code shall include such provision and any regulation or ruling promulgated thereunder.

“Committee” means the Management Compensation and Organization Committee of the Board or such other committee as may be designated by the Board to administer the Plan.

“Corporation” means Mobil Corporation, a Delaware corporation, or its successor.

“Dividend Equivalent” means, in respect of one Stock Equivalent, an amount equal to the amount of the dividend that would be payable on any Dividend Payment Date with respect to one share of Stock.

“Dividend Payment Date” means a date on which dividends are paid with respect to Stock.

“Employee” means any person who is a regular full time employee of the Corporation or an Affiliated Corporation, including such employees who are officers or directors of the Corporation. In the discretion of the Committee, the term may include persons who at the request of the Corporation or any Affiliated Corporation accept employment with any company in which the Corporation directly or indirectly has a substantial interest.

“Fair Market Value” of Stock is the mean between the highest and lowest quoted selling price of Stock on the New York Stock Exchange or, in the discretion of the Committee, as reported by a recognized central market reporting system on the date an Award is granted or on any other date the value of Stock is to be determined, provided that (i) if no sales of Stock shall have been so made on such Exchange or so reported by such central market reporting system on such date, or (ii) if in the opinion of the Committee insufficient sales shall have been made on such date to constitute a representative market, then Fair Market Value shall be determined by taking a weighted average of the means between the highest and lowest sales prices on the nearest representative trading dates before and after the valuation date. The average is to be weighted inversely by the respective numbers of trading days between the trading dates and the valuation date.

“Incentive Award” means a Short-Term Incentive Award or a Long-Term Incentive Award.

“Income Statement” with respect to any fiscal year of the Corporation means the consolidated statement of income and the accompanying notes to financial statements for such year included in the Corporation’s annual report to shareholders.

“Long-Term Incentive Award” means an Award granted pursuant to Section 5.3.

“Named Executive Officer” means an Employee described in Section 162(m)(3) of the Code for the year an Incentive Award is granted.

“Non-Qualified Option” means an Option granted under Article VI which is not a Qualified Option.

“Option” means an Award granted under Article VI in the form of a right to purchase Stock evidenced by an instrument containing such provisions as the Committee may establish.

“Performance Cycle” means any period, beginning not earlier than January 1, 1995, of four successive calendar years.

“Performance Measure” means such measure or indicator of the performance of the Corporation, an Affiliated Corporation, any division, department or identifiable segment thereof, or of any individual recipient of an Award as may be set forth herein or established from time to time by the Committee.

“Plan” means this 1995 Mobil Incentive Compensation and Stock Ownership Plan.

“Prior Plan” means the 1991 Mobil Incentive Compensation and Stock Option Plan.

“Qualified Option” means an option granted under Article VI which is designated by the Committee as a Qualified Option and for which the Code provides for either or both deferral of taxation on exercise or a lower effective rate of tax on recognition of gain than would be available in respect of a Non-Qualified Option.

“Restricted Stock” means Stock which bears such restrictive endorsements as the Committee, in its discretion, shall deem appropriate and necessary to carry out the purpose of this Plan.

“Short-Term Incentive Award” means an Award granted pursuant to Section 5.2.

“Special Item” with respect to any fiscal year of the Corporation means each item in excess of $10 million after tax that is reflected in the Corporation’s Adjusted Net Income for such year and is recorded in accordance with generally accepted accounting principles in one of the following categories:

(a) Gains or losses on asset sales or dispositions;

(b) Asset write downs;

(c) Litigation or claim judgments or settlements;

(d) Accruals for environmental obligations;

(e) Effect of changes in tax law or rate on deferred tax liabilities;

(f) Accruals for restructuring programs; and

(g) Catastrophic property losses.

“Stock” means the publicly traded common stock of the Corporation or any successor, including any adjustments in the event of changes in capital structure of the type described in Article IX.

“Stock Equivalent” means a hypothetical share of Stock credited to an Employee having a value at any time equal to the Fair Market Value of an actual share of Stock at that time. Stock Equivalents may be recorded in full shares only or in full and fractional shares pursuant to such rules as the Committee shall prescribe.

ARTICLE III—ADMINISTRATION OF THE PLAN

3.1 COMPOSITION OF COMMITTEE

This Plan shall be administered by the Committee which shall be composed of not less than four members of the Board as may be designated by the Board; provided that the Committee shall not include any individual who (a) is an officer or employee of the Corporation or any Affiliated Corporation; (b) is a former officer of the Corporation or any Affiliated Corporation; (c) is a former employee of the Corporation or any Affiliated Corporation who receives compensation for prior service (other than benefits under a tax-qualified retirement plan) during the taxable year in which such individual serves on the Committee; (d) is not an outside director as defined under Section 162(m) of the Code; or (e) has been eligible to receive Awards under this Plan or the Prior Plan at any time within the 12-month period immediately prior to service as a member of the Committee; provided that the restrictions set out in clause (d) shall not apply prior to the annual meeting of shareholders of the Corporation in 1996 (or such later date as may be permitted under Section 162(m) of the Code). The Board may designate alternate members of the Committee from eligible Board members to act in the place and stead of any absent member of the Committee.

3.2 QUORUM

A majority of the Committee shall constitute a quorum, and the acts of a majority of the members present at any meeting at which a quorum is present, or acts approved in writing by all of the members in the absence of a meeting, shall be the acts of the Committee. Any one or more members of the Committee may participate in a meeting by means of a conference telephone or similar communications equipment by means of which all persons participating in the meeting can hear and speak to each other. Participation by such means shall constitute presence in person at such meeting.

3.3 POWERS

The Committee shall have full and final authority to operate, manage and administer the Plan on behalf of the Corporation. This authority includes, but is not limited to:

(a) The power to grant Awards conditionally or unconditionally, subject to any applicable limitations in this Plan,

(b) The power to establish Performance Measures upon which Awards shall be based; provided that any changes to the Performance Measures applicable to Named Executive Officers set forth in Article V shall be subject to approval by a separate vote of the shareholders of the Corporation,

(c) The power to make the certification referred to in Section 3.4(b),

(d) The power to reduce the amount of any Award (other than an Award that has become non-forfeitable),

(e) The power to determine whether Incentive Awards shall be expressed in United States currency, shares of Stock, Restricted Stock, or any combination thereof,

(f) The power to prescribe the form or forms of the instruments evidencing Awards granted under this Plan,

(g) The power to pay and to defer payment of Incentive Awards which have become non-forfeitable,

(h) The power to direct the Corporation to make the conversions, accruals and payments provided for by the Plan,

(i) The power to interpret the Plan and to make any determination of fact incident to the operation of the Plan,

(j) The power to provide regulations for the operation of the various features of the Plan, and otherwise to prescribe regulations for the interpretation, management and administration of the Plan,

(k) The power to delegate responsibility for Plan operation, management and administration on such terms, consistent with the Plan, as the Committee may establish,

(l) The power to delegate to other persons the responsibility of performing ministerial acts in furtherance of the Plan’s purpose, and

(m) The power to engage the services of persons, companies, or organizations, including but not limited to banks, insurance companies, brokerage firms, and consultants, in furtherance of the Plan’s purpose.

3.4 CERTIFICATION

No Short-Term Incentive Award or Long-Term Incentive Award will be paid to a Named Executive Officer unless the Committee has certified in writing (which writing may include approved minutes of a meeting of the Committee) that the Adjusted Net Income and Special Items, or the average of the Adjusted Net Income amounts for the years included in a Performance Cycle, as the case may be, was equal to or in excess of the amount required for the granting of such Award hereunder.

3.5 COMMUNICATION OF AWARDS

The Committee shall timely communicate in writing to each Employee to whom an Award is granted in accordance with this Plan a description of such Award, including the terms and any conditions of its payment.

3.6 ACCOUNTS

(a) For the purpose of accounting for provisional Awards and non-forfeitable Awards deferred as to payment, the Corporation shall establish bookkeeping accounts bearing the name of each Employee receiving such Awards. Except as provided below, each account shall be unfunded, and shall not be a trust for the benefit of the Employee; the existence of such accounts shall not give any Employee any rights superior to those of unsecured general creditors of the Corporation.

(b) With respect to non-forfeitable Awards, payment of which is deferred, the Committee may, in its discretion, direct the Corporation:

(i) To pay an amount equal to such Award to a trustee or fiduciary in trust for the benefit of one or more Employees, as the Committee may designate, with instructions to provide for the investment thereof during any period of deferment; or

(ii) To allocate an amount equal to such Award to an investment manager (who may, but need not, be an Employee of the Corporation or an Affiliated Corporation) with instructions to provide for the investment thereof during the period of deferment either in the discretion of such manager or one or more designated investment advisors.

ARTICLE IV—ELIGIBILITY

4.1 ELIGIBLE EMPLOYEES

Awards will be granted only to key Employees described in Article I, selected or determined by (or pursuant to delegation of authority from) the Committee in its sole discretion. An Incentive Award may be granted within a reasonable period after an employee's termination of service and such Incentive Award shall be deemed granted to an Employee. Neither the members of the Committee nor any member of the Board who is not an Employee shall be eligible to receive an Award. In lieu of determining individual Employees to whom Awards may be granted and the amounts of such Awards, the Committee may in its discretion from time to time authorize such determinations with respect to Employees other than Named Executive Officers to be made by the Chief Executive Officer or by senior management of the divisions, departments or other identifiable segments of the Corporation or of Affiliated Corporations or their divisions, departments or other identifiable segments, provided that such determinations shall be made in accordance with such rules, regulations and guidance as the Committee shall prescribe. Named Executive Officers, other Officers of the Corporation, Directors who are Employees and other Employees to whom the Committee delegates final authority to determine Awards under the Plan are eligible only for Awards granted directly by the Committee.

4.2 RELEVANT FACTORS

In selecting individual Employees to whom Awards shall be granted at any time, as well as in determining the amount, type, terms and conditions of any Award, the Committee (or as authorized, its representative) shall weigh such factors as are relevant to accomplish the purpose of the Plan as stated in Article I. No Employee shall be eligible for the grant of any Option under the Plan if at the time of grant the Employee, directly or indirectly, owns Stock possessing more than 5% of the combined voting power of all classes of Stock of the Corporation and its Affiliated Corporations. No Named Executive Officer shall be eligible for the grant of any Award that would cause the applicable amounts in Articles V or VI to be exceeded.

ARTICLE V—INCENTIVE AWARDS

5.1 PROVISIONAL AND NON-FORFEITABLE INCENTIVE AWARDS

The Committee may in its discretion grant Incentive Awards that are provisional or non-forfeitable in accordance with such criteria, at such intervals, in such form and upon such conditions as the Committee may establish, subject to the limitations set forth in this Plan. Incentive Awards, whether provisional or non-forfeitable, may be expressed in United States currency, shares of Stock, shares of Restricted Stock or any combination thereof, and upon satisfaction of the relevant conditions, if any, may be paid or distributed currently, deferred for payment at a later date, or paid in part currently and in part at a later date, all as the Committee in its discretion shall determine.

5.2 SHORT-TERM INCENTIVE AWARDS

The Committee in its sole discretion may grant or approve Short-Term Incentive Awards to Employees from time to time. The amounts of such Awards shall be determined on the basis of such Performance Measures as the Committee shall establish from time to time. In the case of Named Executive Officers, the Performance Measure for Short-Term Incentive Awards shall be the Adjusted Net Income for the year prior to the year in which any such Award is granted, further adjusted to exclude the effects of any Special Items for such year.

The amount of the Short-Term Incentive Award for any year to a Named Executive Officer who is the Chief Executive Officer shall be 0.1% of such Performance Measure, and the amount of the Short-Term Incentive Award for any year to any other Named Executive Officer shall be 0.0375% of such Performance Measure, in each case subject to reduction pursuant to Section 5.4.

5.3 LONG-TERM INCENTIVE AWARDS

(a) The Committee in its sole discretion may grant Allotments comprised of a specified number of Stock Equivalents to Employees from time to time. Each Allotment shall be granted during the first year of, and shall be in respect of, a Performance Cycle and shall remain provisional until the Committee grants or determines not to grant a Long-Term Incentive Award in respect of such Allotment pursuant to Section 5.3(c). The maximum number of Stock Equivalents that may comprise Allotments granted at any time during any calendar year during any part of which this Plan is in effect shall be the number of shares of Stock in the Authorized Share Pool for such calendar year reduced by:

(i) the number of shares of Stock upon which Options have theretofore been granted pursuant to Section 6.2 during such calendar year;

(ii) the number of Stock Equivalents comprising Allotments that have theretofore been granted pursuant to this Section 5.3(a) during such calendar year;

(iii) the number of Stock Equivalents comprising Allotment Supplements that have theretofore been credited pursuant to Section 5.3(b) during such calendar year or are reasonably estimated to be so credited during the remainder of such calendar year; and

(iv) the number of shares of Restricted Stock, if any, that have theretofore been awarded pursuant to Section 5.3(d) during such calendar year.

(b) On each Dividend Payment Date after the Award Date of any Allotment, an Allotment Supplement shall be credited in respect of such Allotment and any Allotment Supplements theretofore credited pursuant to this Section 5.3(b) in respect of such Allotment. The number of Stock Equivalents that shall comprise an Allotment Supplement shall be determined by dividing (i) the Dividend Equivalents in respect of the number of Stock Equivalents that comprise such Allotment and any Allotment Supplements theretofore credited pursuant to this Section 5.3(b) in respect of such Allotment by (ii) the Fair Market Value of a share of Stock on the Dividend Payment Date.

(c) After the end of each Performance Cycle, all Stock Equivalents that comprise an Allotment in respect of such Performance Cycle and all Allotment Supplements theretofore credited in respect of such Allotment shall be converted to a Long-Term Incentive Award in an amount, if any, to be based on Performance Measures established by the Committee from time to time. In the case of each Named Executive Officer, the Performance Measure shall be Adjusted Net Income, and the amount of the Long-Term Incentive Award granted to each such Officer in respect of a Performance Cycle, irrespective of the number of Stock Equivalents credited to the account of such Officer in respect of such Performance Cycle, shall be 0.2% of the average of the Adjusted Net Income for each of the four years of such Performance Cycle, subject to reduction pursuant to Section 5.4.

(d) In addition to the Long-Term Incentive Awards described in Sections 5.3(a), (b) and (c), the Committee in its sole discretion may grant Long-Term Incentive Awards in the form of Restricted Stock to such Employees as it shall identify as having extraordinary potential to make a long-term contribution to the success of the Corporation. The maximum number of shares of Restricted Stock that can be the subject of any such grant shall be 10,000, subject to adjustment in accordance with Article IX. No Award may be made pursuant to this Section 5.3(d) to any person who at the time of the Award holds Restricted Stock granted pursuant to this Section 5.3(d) as to which all restrictions applicable to such Restricted Stock have not lapsed. The foregoing determination as to whether restrictions have lapsed shall be made without regard to any potential or actual modification of such restrictions after the original grant date. The maximum number of shares of Restricted Stock that may be granted at any time during any calendar year during any part of which this Plan is in effect shall be the number of shares in the Authorized Share Pool for such calendar year reduced by:

(i) the number of shares of Stock upon which Options have theretofore been granted pursuant to Section 6.2 during such calendar year;

(ii) the number of Stock Equivalents comprising Allotments that have theretofore been granted pursuant to Section 5.3(a) during such calendar year;

(iii) the number of Stock Equivalents comprising Allotment Supplements that have theretofore been credited pursuant to Section 5.3(b) during such calendar year or are reasonably expected to be so credited during the remainder of such calendar year; and

(iv) the number of shares of Restricted Stock that have theretofore been awarded pursuant to this Section 5.3(d) during such calendar year.

5.4 REDUCTION OF AWARDS

(a) The Committee in its sole discretion may, but shall not be required to, reduce the amount of, or not grant, any Short-Term Incentive Award or any Long-Term Incentive Award that could otherwise be granted, based on such Performance Measures or other considerations as it deems appropriate.

(b) No Short-Term Incentive Award or Long-Term Incentive Award that could otherwise be granted shall be granted if no dividend has been paid to holders of Stock in the preceding 12 months. Allotments or Allotment Supplements with respect to which Long-Term Incentive Awards are prohibited by the preceding sentence shall be cancelled.

5.5 DEATH OF EMPLOYEE

Any provisional Incentive Award shall be cancelled upon death of the Employee during the provisional period except as the Committee may otherwise provide. If a provisional Incentive Award is cancelled by reason of the death of the Employee, the Committee may authorize an alternative disposition in its discretion.

5.6 DEFERRAL OF INCENTIVE AWARDS

The Committee may, in its sole discretion, permit or require deferral of payment of any Incentive Award, subject to such terms, conditions, rules and regulations as the Committee shall prescribe. Deferred Incentive Awards may be denominated in Stock Equivalents or such other units as the Committee shall prescribe. Where a deferred Incentive Award is denominated in Stock Equivalents, each such Stock Equivalent shall be valued at an amount equal to the Fair Market Value of a share of Stock on the date that payment would have been due but for the deferral (or the Fair Market Value of a share of Stock averaged over such dates as the Committee shall establish from time to time). An account bearing the name of the Employee as provided in Section 3.6 shall be credited with the number of Stock Equivalents determined on the basis of such value. Each such account shall also be credited on each Dividend Payment Date with an amount of Dividend Equivalents in respect of the Stock Equivalents in the account. Dividend Equivalents may, in the discretion of the Committee, be disbursed in cash to the Employee to whose account they have been credited or accumulated in such account in the form of additional Stock Equivalents based on the Fair Market Value of a share of Stock on the Dividend Payment Date. Stock Equivalents resulting from deferral of Incentive Awards shall not be charged against any Authorized Share Pool.

5.7 PAYMENT OF INCENTIVE AWARDS

Payment of Incentive Awards shall be made, in the sole discretion of the Committee, in cash, Stock, Restricted Stock, or any combination of cash, Stock and Restricted Stock; provided that the Committee may prescribe by regulation circumstances in which amounts payable to any person who is or was a director or officer subject to Section 16 of the Securities Exchange Act of 1934 shall be paid solely in cash.

ARTICLE VI—STOCK OPTION AWARDS

6.1 NUMBER OF SHARES

The maximum number of shares of Stock upon which Options may be granted at any time during any calendar year during any part of which this Plan is in effect shall be the number of shares in the Authorized Share Pool for such calendar year reduced by:

(a) the number of shares of Stock upon which Options have theretofore been granted pursuant to Section 6.2 during such calendar year;

(b) the number of Stock Equivalents comprising Allotments that have theretofore been granted pursuant to Section 5.3(a) during such calendar year;

(c) the number of Stock Equivalents comprising Allotment Supplements that have theretofore been credited pursuant to Section 5.3(b) during such calendar year or are reasonably estimated to be so credited during the remainder of such calendar year; and

(d) the number of shares of Restricted Stock that have theretofore been awarded pursuant to Section 5.3.(d) during such calendar year.

Of the shares of Stock upon which Options may be granted in any year pursuant to the foregoing sentence, no more than 2,000,000 shares (subject to adjustment pursuant to Article IX) per year, cumulative from the effective date of the Plan, shall be available for the grant of Incentive Stock Options.

6.2 OPTION GRANTS

The Committee in its sole discretion may from time to time grant Options on such terms and subject to such conditions as it shall deem appropriate, subject to the applicable provisions of this Plan; provided that the maximum number of shares of Stock upon which Options may be granted to any Employee in any calendar year shall be 150,000, subject to adjustment as provided in Article IX. As to each Option, the Committee shall have full and final authority in its discretion: (a) to determine whether the same shall be a Qualified Option or a Non-Qualified Option or both, (b) to determine the number of shares of Stock subject to each Option, subject to the limit set forth in the immediately preceding sentence, (c) to determine the purchase price of the shares of Stock subject to each Option (the "Option Price"), which price shall be not less than the minimum price specified in Section 6.4, and (d) to determine the time or times when each Option shall become exercisable and the duration of the exercise period, which period shall not exceed the maximum period specified in Section 6.3.

6.3 TERM OF OPTIONS

The full term of each Option granted hereunder shall be for such period as the Committee shall determine, but not for more than ten years from the date of granting thereof. Each Option shall be subject to earlier termination as provided in Sections 6.8 and 6.9.

6.4 OPTION PRICE

The Option Price shall be determined by the Committee at the time any Option is granted and shall be not less than 100 percent of the Fair Market Value of the shares covered thereby at the time the Option is granted (but in no event less than par value).

6.5 NON-TRANSFERABILITY OF OPTIONS

No Option granted under this Plan shall be transferable by the grantee otherwise than by will or the laws of descent and distribution, and such Option may be exercised during the grantee's lifetime only by the grantee; provided that the Committee may in its sole discretion provide in the instrument evidencing any Non-Qualified Option any terms and conditions upon which such Non-Qualified Option may be transferred if the Committee determines, based upon such advice of counsel (which may be counsel to the Corporation) as it deems appropriate, that a Registration Statement under the Securities Act of 1933 is in effect, or an exemption from the requirements for such a Registration Statement exists, for each of (a) the transfer of such Non-Qualified Option; (b) the issuance of Stock to the transferee of the Non-Qualified Option upon exercise of the Non-Qualified Option; and (c) any sale by the transferee of the Option of Stock issued to such transferee upon exercise of the Non-Qualified Option.

6.6 INCENTIVE STOCK OPTIONS

Any Option issued hereunder which is intended to qualify as an "incentive stock option" as described in Section 422 of the Code (an "ISO") shall be subject to the limitations or requirements as may be necessary for the purposes of Section 422 of the Code to the extent and in such form as determined by the Committee in its discretion.

6.7 EXERCISE OF OPTIONS

Each Option granted under this Plan shall be exercisable on such date or dates and during such period and for such number of shares as shall be determined pursuant to the provisions of the instrument evidencing such Option. A person electing to exercise an Option shall give written notice to the Corporation or its agent of such election and of the number of shares he or she has elected to purchase and shall at the time of exercise tender the full purchase price of the shares he or she has elected to purchase plus any required withholding taxes. Until a certificate or certificates for the shares so purchased has been issued to, or for the benefit of, such person, or until an entry in lieu of such a certificate is made on the stock books of the Corporation, he or she shall possess no rights of a record holder with respect to any of such shares. The purchase price may be paid in cash, by certified check or in shares of Stock (excluding fractional shares) or any combination thereof. Shares of Stock delivered in payment of the purchase price shall be valued at the Fair Market Value of such shares on the date of exercise of the Option. The shares to be delivered upon exercise of Options under this Plan shall be made available, at the discretion of the Board, either from authorized but unissued shares or from previously issued and reacquired shares of Stock held by the Corporation as treasury shares, including shares purchased in the open market.

6.8 OPTION UNAFFECTED BY CHANGE IN DUTIES

No Option shall be affected by any change of duties or position of the optionee (including transfer to or from an Affiliated Corporation), so long as he or she continues to be an Employee. If an optionee shall cease to be an Employee for any reason other than death, such Option shall thereafter be exercisable only to the extent of the purchase rights, if any, which have accrued as of the date of such cessation; provided that (i) the Committee may provide in the instrument evidencing any Option that the Committee may in its absolute discretion, upon any such cessation of employment, determine (but be under no obligation to determine) that such accrued purchase rights shall be deemed to include additional shares covered by such Option and (ii) unless the Committee shall otherwise provide in the instrument evidencing any Option, upon any such cessation of employment, such remaining rights to purchase shall in any event terminate upon the expiration of the original term of the Option where such cessation of employment is on account of retirement under a Corporation sponsored retirement plan on or after the Employee attains age sixty, on account of long-term disability, or on account of any other reason specified by the Committee, or its delegate, for the purpose of making this clause applicable, and otherwise, upon the expiration of three months from such date of termination, but in no event later than the expiration of the original term of the Option.

6.9 DEATH OF OPTIONEE

Should an optionee die while in possession of the legal right to exercise an Option or Options under this Plan, such person (the “personal representative”) as shall have acquired, by will or by the laws of descent and distribution, the right to exercise any Option theretofore granted may exercise such Option (i) at any time up to the expiration of the original term of the Option in the following cases: (a) where the optionee was an Employee on the date of death and (b) where the optionee was not an Employee on the date of death and his or her employment ceased on account of retirement under a Corporation sponsored plan on or after the Employee attained age sixty, on account of long term disability, or on account of any other reason specifically approved by the Committee or its delegate for the purpose of making this clause applicable; or (ii) at any time prior to one year from the date of death where the optionee was not an Employee on the date of death and his or her employment ceased on account of a cause other than those specified in clause (i)(b) above, provided that such Option shall expire in all events no later than the last day of the original term of such Option, and provided further, that any such exercise shall be limited to the purchase rights which have accrued as of the date when the optionee ceased to be such an Employee, whether by death or otherwise, provided further, however, that the Committee may provide in the instrument evidencing any Option that all shares covered by such Option shall become subject to purchase immediately upon the death of the optionee.

ARTICLE VII—BENEFITS PLANS

Incentive Awards, Awards of Restricted Stock and Awards of Options under the Plan are discretionary and are additional to and not a part of regular salary. Incentive Awards, Awards of Restricted Stock and Awards of Options may not be used in determining the amount of compensation for any purpose under the benefit plans of the Corporation, or an Affiliated Corporation, except (1) an Incentive Award made to an

Employee may be used in determining the amount of compensation for the purpose of any retirement or life insurance plan of the Corporation and its Affiliated Corporations to the extent provided from time to time in such plan, and (2) as the Committee may otherwise from time to time expressly provide.

ARTICLE VIII—AMENDMENT, SUSPENSION OR TERMINATION OF THE PLAN

The Board may suspend the Plan or any part thereof at any time or may terminate the Plan in its entirety. Awards shall not be granted under any part of the Plan affected by a suspension, nor shall Awards be granted after Plan termination.

The Board may also amend the Plan from time to time, except that amendments which affect the following subjects must be approved by shareholders of the Corporation:

(a) The qualifications for eligibility to become or remain a member of the Committee;

(b) The Performance Measures and the amounts of the Short-Term Incentive Awards and the Long-Term Incentive Awards for Named Executive Officers;

(c) Except as provided in Article IX relating to capital changes, the number of shares in the Authorized Share Pool for any calendar year, the maximum number of shares of Stock upon which Options may be granted to any person in any calendar year and the maximum number of shares of Restricted Stock that may be awarded to any person pursuant to Section 5.3(d);

(d) The maximum term of Options granted;

(e) The minimum Option Price;

(f) The term of the Plan;

(g) The requirements as to eligibility for participation in the Plan;

(h) The prohibition against granting Awards to a member of the Committee; and

(i) The provision requiring that Employees to whom the Committee has delegated final authority to determine Awards under the Plan are eligible only for Awards granted directly by the Committee.

Awards granted prior to suspension or termination of the Plan may not be cancelled solely because of such suspension or termination, except with the consent of the grantee of the Award.

ARTICLE IX—CHANGES IN CAPITAL STRUCTURE

Stock, Stock Equivalents, Restricted Stock and the instruments evidencing Options granted hereunder shall be subject to adjustments in the event of changes in the outstanding stock of the Corporation by reason of Stock dividends, Stock splits, recapitalizations, reorganizations, mergers, consolidations, combinations, exchanges or other relevant changes in capitalization occurring after the date of an Award to the same extent as would affect an actual share of Stock issued and outstanding on the effective date of such change. In the event of any such change, the aggregate number and classes of shares comprising the Authorized Share Pool for the calendar year in which such change occurs, the number of shares upon which Options may thereafter be granted to any person pursuant to Section 6.2, and the number of shares of Restricted Stock that may thereafter be awarded to any person pursuant to Section 5.3(d) shall be appropriately adjusted as determined by the Board so as to reflect such change.

ARTICLE X—EFFECTIVE DATE AND TERM OF THE PLAN

The Plan became effective January 1, 1995, subject to the affirmative vote of the holders of shares entitled to cast a majority of the votes entitled to be cast (in person or by proxy) for or against approval of the Plan at the Annual Meeting of the shareholders of the Corporation in 1995. The Plan shall continue until such time as it may be terminated by action of the Board; provided, however, that the Plan, if not so terminated, shall be submitted to the shareholders of the Corporation for their approval not later than December 31, 2000. No Options may be granted under this Plan subsequent to April 30, 2000.

ARTICLE XI—TRANSITION—1991 INCENTIVE COMPENSATION AND STOCK OPTION PLAN

(a) This Plan supersedes the Prior Plan, and no new Incentive Awards or Options, as defined in the Prior Plan, may be granted under the Prior Plan after the effective date of this Plan, except that (i) short-term incentive awards in respect of 1994 shall be payable pursuant to the Prior Plan in 1995 and (ii) options granted in 1995 to persons, other than Named Executive Officers, that are subject to the laws of any foreign jurisdiction that require, or condition favorable tax treatment on, approval of the plan pursuant to which options are granted prior to the grant thereof shall be granted pursuant to the Prior Plan but shall count against the Authorized Share Pool for 1995; provided that nothing herein shall modify the terms of the Prior Plan if this Plan is not approved by vote of the shareholders of the Corporation as contemplated by Article X. Incentive Awards including conditional Incentive Awards made and Options granted under the Prior Plan before the effective date of this Plan shall remain outstanding and shall be administered under the terms of the Prior Plan.

(b) Any Awards granted under this Plan prior to approval of this Plan by the shareholders of the Corporation shall be conditional upon, and forfeited upon the failure of, such approval at the Annual Meeting of Stockholders of Mobil Corporation in 1995; provided that failing such approval any such Award to a person other than a Named Executive Officer that could have been granted under the terms of the Prior Plan may, in the discretion of the Committee, be deemed to have been so granted.

EXXON MOBIL CORPORATION

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2005	2004	2003	2002	2001
			(millions of dollars)		
Income from continuing operations	$36,130	$25,330	$20,960	$11,011	$15,003
Excess/(shortfall) of dividends over earnings of affiliates owned less than 50 percent accounted for by the equity method	(513)	(475)	(205)	(140)	(108)
Provision for income taxes(1)	24,885	16,644	11,734	7,073	9,599
Capitalized interest	(89)	(180)	(180)	(143)	(255)
Minority interests in earnings of consolidated subsidiaries	795	773	692	206	556
	61,208	42,092	33,001	18,007	24,795
Fixed Charges:(1)					
Interest expense—borrowings	200	182	182	368	328
Capitalized interest	443	515	497	442	529
Rental expense representative of interest factor	593	498	424	587	621
Dividends on preferred stock	7	5	3	5	8
	1,243	1,200	1,106	1,402	1,486
Total adjusted earnings available for payment of fixed charges	$62,451	$43,292	$34,107	$19,409	$26,281
Number of times fixed charges are earned	50.2	36.1	30.8	13.8	17.7

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.

Subsidiaries of the Registrant (1), (2) and (3) — at December 31, 2005

	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	100	Delaware
Exxon International Finance Company	100	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	100	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 Energy	100	Canada
ExxonMobil Canada Ltd.	100	Canada
ExxonMobil Canada Properties	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 de Colombia S.A.	99.42	Colombia
ExxonMobil Delaware Holdings Inc.	100	Delaware
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 Finance Company Limited	100	England
ExxonMobil Gas Marketing Deutschland GmbH	99.999	Germany
ExxonMobil Gas Marketing Deutschland GmbH & Co. KG	50	Germany
ExxonMobil Gas Marketing Europe Limited	100	England
ExxonMobil Global Services Company	100	Delaware
ExxonMobil Holding Company Holland LLC	100	Delaware
ExxonMobil Holding Norway AS	100	Norway
ExxonMobil Hong Kong Limited	100	Hong Kong
ExxonMobil Hungary Finance Kft.	100	Hungary
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

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
ExxonMobil Oil & Gas Investments Limited	100	Bahamas
ExxonMobil Oil Corporation	100	New York
ExxonMobil Oil Indonesia Inc.	100	Cayman Island
ExxonMobil Permian Basin Inc.	100	Delaware
ExxonMobil Petroleum & Chemical, BVBA	100	Belgium
ExxonMobil Petroleum & Chemical Holdings Inc.	100	Delaware
ExxonMobil Pipeline Company	100	Delaware
ExxonMobil Production Deutschland GmbH	100	Germany
ExxonMobil Production Norway Inc.	100	Delaware
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
Imperial Oil Petroliere Imperiale, (an Ontario General Partnership)	69.6	Canada
Imperial Oil Resources (an Alberta limited partnership)	69.6	Canada
Imperial Oil Resources N.W.T. 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	Cayman Island
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 Services (Bahamas) Limited	100	Bahamas
Mobil Yanbu Petrochemical Company Inc.	100	Delaware
Mobil Yanbu Refining Company Inc.	100	Delaware
Nansei Sekiyu Kabushiki Kaisha (6)	43.77	Japan

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Nederlandse Aardolie Maatschappij B.V. (4) (5)	50	Netherlands
Qatar Liquefied Gas Company Limited (5)	10	Qatar
Qatar Liquefied Gas Company Limited (II) (5)	30	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (5)	24.999	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (II) (5)	30	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (3) (5)	30	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
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.

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, 2006, 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, 2006

EXHIBIT 31.1

Certification by Rex W. Tillerson
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Rex W. Tillerson, 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, 2006

/s/ REX W. TILLERSON
Rex W. Tillerson
Chief Executive Officer

EXHIBIT 31.2

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, 2006

/s/ DONALD D. HUMPHREYS

Donald D. Humphreys
Senior Vice President and Treasurer
(Principal Financial Officer)

EXHIBIT 31.3

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, 2006

/s/ PATRICK T. MULVA

Patrick T. Mulva
Vice President and Controller
(Principal Accounting Officer)

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, Rex W. Tillerson, 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, 2005, 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, 2006

/s/ REX W. TILLERSON

Rex W. Tillerson
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, 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, 2005, 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, 2006

/s/ DONALD D. HUMPHREYS

Donald D. Humphreys
Senior 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.

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, 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, 2005, 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, 2006

/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.