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2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K/A
Amendment No. 1

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

For the fiscal year ended December 31, 2010

or

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

For the transition period from to

Commission File Number 1-2256

EXXON MOBIL CORPORATION

(Exact name of registrant as specified in its charter)

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

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 444-1000

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, without par value (4,958,598,361 shares outstanding at January 31, 2011)	**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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ü Accelerated filer ___

Non-accelerated filer ___ Smaller reporting company ___

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, 2010, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $57.07 on the New York Stock Exchange composite tape, was in excess of $290 billion.

Documents Incorporated by Reference:

Proxy Statement for the 2011 Annual Meeting of Shareholders (Part III)

EXPLANATORY NOTE

This Amendment No. 1 is being filed solely for the purpose of inserting the conformed signature of independent auditors on their report on page 63, which was inadvertently omitted from the initial filing, and to correct additional typographical printer's errors in a heading and officer name on page 62. Except for these corrections, there have been no changes in any of the financial or other information contained in the report. For convenience, the entire Annual Report on Form 10-K, as amended, is being re-filed.

EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2010

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PART I

Item 1. ***Business.***

Exxon Mobil Corporation was incorporated in the State of New Jersey in 1882. Divisions and affiliated companies of ExxonMobil operate or market products in the United States and most other countries of the world. 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.

On June 25, 2010, ExxonMobil acquired XTO Energy Inc. (“XTO”) by merging a wholly-owned subsidiary of ExxonMobil with and into XTO (the “merger”), with XTO continuing as the surviving corporation and a wholly-owned subsidiary of ExxonMobil. Each share of XTO common stock was converted into the right to receive 0.7098 shares of common stock of ExxonMobil plus cash in lieu of fractional shares. The merger combines XTO’s high-quality unconventional gas and oil shale reserve base and technical expertise in unconventional development with ExxonMobil’s research and development expertise, project management and operational skill, global scale, and financial capacity. Details of the merger transactions are contained in the Financial Section of this report under the following: “Note 19: Acquisition of XTO Energy Inc.”

Throughout ExxonMobil’s businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels as well as projects to monitor and reduce nitrogen oxide, sulfur oxide, and greenhouse gas emissions and expenditures for asset retirement obligations. ExxonMobil’s 2010 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil’s share of equity company expenditures, were about $4.5 billion, of which $1.9 billion were capital expenditures and $2.6 billion were included in expenses. The total cost for such activities is expected to remain in this range in 2011 and 2012 (with capital expenditures approximately 40 percent of the total).

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.

Operating data and industry segment information for the Corporation are contained in the Financial Section of this report under the following: “Quarterly Information”, “Note 17: Disclosures about Segments and Related Information” and “Operating Summary”. Information on oil and gas reserves is contained in the “Oil and Gas Reserves” part of the “Supplemental Information on Oil and Gas Exploration and Production Activities” portion of the Financial Section of this report.

ExxonMobil has a long-standing commitment to the development of proprietary technology. We have a wide array of research programs designed to meet the needs identified in each of our business segments. Information on Company-sponsored research and development spending is contained in "Note 3: Miscellaneous Financial Information" of the Financial Section of this report. ExxonMobil held approximately 11 thousand active patents worldwide at the end of 2010. For technology licensed to third parties, revenues totaled approximately $125 million in 2010. Although technology is an important contributor to the overall operations and results of our Company, the profitability of each business segment is not dependent on any individual patent, trade secret, trademark, license, franchise or concession.

The number of regular employees was 83.6 thousand, 80.7 thousand and 79.9 thousand at years ended 2010, 2009 and 2008, 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 20.1 thousand, 22.0 thousand and 24.8 thousand at years ended 2010, 2009 and 2008, respectively.

Information concerning the source and availability of raw materials used in the Corporation's business, the extent of seasonality in the business, the possibility of renegotiation of profits or termination of contracts at the election of governments and risks attendant to foreign operations may be found in "Item 1A–Risk Factors" and "Item 2–Properties" in this report.

ExxonMobil maintains a website at 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. Information on our website is not incorporated into this report.

Item 1A. *Risk Factors*.

ExxonMobil's financial and operating results are subject to a variety of risks inherent in the global oil, gas, and petrochemical businesses. Many of these risk factors are not within the Company's control and could adversely affect our business, our financial and operating results or our financial condition. These risk factors include:

Supply and Demand.

The oil, gas, and petrochemical businesses are fundamentally commodity businesses. This means ExxonMobil's operations and earnings may be significantly affected by changes in oil, gas and petrochemical prices and by changes in margins on 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.

Economic conditions. The demand for energy and petrochemicals correlates closely with general economic growth rates. The occurrence of recessions or other periods of low or negative economic growth will typically have a direct adverse impact on our results. Other factors that affect general economic conditions in the world or in a major region, such as changes in population growth rates or periods of civil unrest, also impact the demand for energy and petrochemicals. Economic conditions that impair the functioning of financial markets and institutions also pose risks to ExxonMobil, including risks to the safety of our financial assets and to the ability of our partners and customers to fulfill their commitments to ExxonMobil.

Other demand-related factors. Other factors that may affect the demand for oil, gas and petrochemicals, and therefore impact our results, include technological improvements in energy efficiency; seasonal weather patterns, which affect the demand for energy associated with heating and cooling; increased competitiveness of alternative energy sources that have so far generally not been competitive with oil and gas without the benefit of government subsidies or mandates; and changes in technology or consumer preferences that alter fuel choices, such as toward alternative fueled vehicles.

Other supply-related factors. Commodity prices and margins also vary depending on a number of factors affecting supply. For example, increased supply from the development of new oil and gas supply sources and technologies to enhance recovery from existing sources tend to reduce commodity prices to the extent such supply increases are not offset by commensurate growth in demand. Similarly, increases in industry refining or petrochemical manufacturing capacity tend to reduce margins on the affected products. World oil, gas, and petrochemical supply levels can also be affected by factors that reduce available supplies, such as adherence by member countries to OPEC production quotas and the occurrence of wars, hostile actions, natural disasters, disruptions in competitors' operations, or unexpected unavailability of distribution channels that may disrupt supplies. Technological change can also alter the relative costs for competitors to find, produce, and refine oil and gas and to manufacture petrochemicals.

Other market factors. ExxonMobil's business results are also exposed to potential negative impacts due to changes in currency exchange rates, interest rates, inflation, and other local or regional market conditions. We generally do not use financial instruments to hedge market exposures.

Government and Political Factors.

ExxonMobil's results can be adversely affected by political or regulatory developments affecting our operations.

Access limitations. A number of countries limit access to their oil and gas resources, or may place resources off-limits from development altogether. Restrictions on foreign investment in the oil and gas sector tend to increase in times of high commodity prices, when national governments may have less need of outside sources of private capital. Many countries also restrict the import or export of certain products based on point of origin.

Restrictions on doing business. As a U.S. company, ExxonMobil is subject to laws prohibiting U.S. companies from doing business in certain countries, or restricting the kind of business that may be conducted. Such restrictions may provide a competitive advantage to our non-U.S. competitors unless their own home countries impose comparable restrictions.

Lack of legal certainty. Some countries in which we do business lack well-developed legal systems, or have not yet adopted clear regulatory frameworks for oil and gas development. Lack of legal certainty exposes our operations to increased risk of adverse or unpredictable actions by government officials, and also makes it more difficult for us to enforce our contracts. In some cases these risks can be partially offset by agreements to arbitrate disputes in an international forum, but the adequacy of this remedy may still depend on the local legal system to enforce an award.

Regulatory and litigation risks. Even in countries with well-developed legal systems where ExxonMobil does business, we remain exposed to changes in law (including changes that result from international treaties and accords) that could adversely affect our results, such as increases in taxes or government royalty rates (including retroactive claims); price controls; changes in environmental regulations or other laws that increase our cost of compliance or reduce or delay available business opportunities (including changes in laws related to offshore drilling operations, water use, or hydraulic fracturing); adoption of regulations mandating the use of alternative fuels or uncompetitive fuel components; government actions to cancel contracts or renegotiate terms unilaterally; and expropriation. Legal remedies available to compensate us for expropriation or other takings may be inadequate. We also may be adversely affected by the outcome of litigation or other legal proceedings, especially in countries such as the United States in which very large and unpredictable punitive damage awards may occur.

Security concerns. Successful operation of particular facilities or projects may be disrupted by civil unrest, acts of sabotage or terrorism, and other local security concerns. Such concerns may require us to incur greater costs for security or to shut down operations for a period of time.

Climate change and greenhouse gas restrictions. Due to concern over the risk of climate change, a number of countries have adopted, or are considering the adoption of, regulatory frameworks to reduce greenhouse gas emissions. These include adoption of cap and trade regimes, carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates for renewable energy. These requirements could make our products more expensive, lengthen project implementation times, and reduce demand for hydrocarbons, as well as shifting hydrocarbon demand toward relatively lower-carbon sources such as natural gas. Current and pending greenhouse gas regulations may also increase our compliance costs, such as for monitoring or sequestering emissions.

Government sponsorship of alternative energy. Many governments are providing tax advantages and other subsidies and mandates to make alternative energy sources more competitive against oil and gas. Governments are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. We are conducting our own research efforts into alternative energy, such as through sponsorship of the Global Climate and Energy Project at Stanford University and research into hydrogen fuel cells and fuel-producing algae. Our future results may depend in part on the success of our research efforts and on our ability to adapt and apply the strengths of our current business model to providing the competitive energy products of the future. See "Management Effectiveness" below.

Management Effectiveness.

In addition to external economic and political factors, our future business results also depend on our ability to manage successfully those factors that are at least in part within our control. The extent to which we manage these factors will impact our performance relative to competition. For projects in which we are not the operator, we depend on the management effectiveness of one or more coventurers whom we do not control.

Exploration and development program. Our ability to maintain and grow our oil and gas production depends on the success of our exploration and development efforts. Among other factors, we must continuously improve our ability to identify the most promising resource prospects and apply our project management expertise to bring discovered resources on line on schedule.

Project management. The success of ExxonMobil's Upstream, Downstream, and Chemical businesses depends on complex, long-term, capital intensive projects. These projects in turn require a high degree of project management expertise to maximize efficiency. Specific factors that can affect the performance of major projects include our ability to: negotiate successfully with joint venturers, partners, governments, suppliers, customers, or others; model and optimize reservoir performance; develop markets for project outputs, whether through long-term contracts or the development of effective spot markets; manage changes in operating conditions and costs, including costs of third party equipment or services such as drilling rigs and shipping; prevent, to the extent possible, and respond effectively to unforeseen technical difficulties that could delay project startup or cause unscheduled project downtime; and influence the performance of project operators where ExxonMobil does not perform that role.

Operational efficiency. An important component of ExxonMobil's competitive performance, especially given the commodity-based nature of many of our businesses, is our ability to operate efficiently, including our ability to manage expenses and improve production yields on an ongoing basis. This requires continuous management focus, including technology improvements, cost control, productivity enhancements and regular reappraisal of our asset portfolio.

Research and development. To maintain our competitive position, especially in light of the technological nature of our businesses and the need for continuous efficiency improvement, ExxonMobil's research and development organizations must be successful and able to adapt to a changing market and policy environment.

Safety, business controls, and environmental risk management. Our results depend on management's ability to minimize the inherent risks of oil, gas, and petrochemical operations and to control effectively our business activities. We apply rigorous management systems and continuous focus to workplace safety and to avoiding spills or other adverse environmental events. For example, we work to minimize spills through a combined program of effective operations integrity management, ongoing upgrades, key equipment replacements, and comprehensive inspection and surveillance. Similarly, we are implementing cost-effective new technologies and adopting new operating practices to reduce air emissions, not only in response to government requirements but also to address community priorities. We also maintain a disciplined framework of internal controls and apply a controls management system for monitoring compliance with this framework. Substantial liabilities and other adverse impacts could result if our management systems and controls do not function as intended. The ability to insure against such risks is limited by the capacity of the applicable insurance markets, which may not be sufficient.

Preparedness. Our operations may be disrupted by severe weather events, natural disasters, human error, and similar events. For example, hurricanes may damage our offshore production facilities or coastal refining and petrochemical plants in vulnerable areas. Our ability to mitigate the adverse impacts of these events depends in part upon the effectiveness of our rigorous disaster preparedness and response planning, as well as business continuity planning.

Projections, estimates and descriptions of ExxonMobil's plans and objectives included or incorporated in Items 1, 1A, 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.

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Item 2. ***Properties.***

Information with regard to oil and gas producing activities follows:

1. Disclosure of Reserves

A. Summary of Oil and Gas Reserves at Year-End 2010

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and equity companies. The Corporation has reported proved reserves on the basis of the average of the first-day-of-the-month price for each month during the last 12-month period. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. No major discovery or other favorable or adverse event has occurred since December 31, 2010, that would cause a significant change in the estimated proved reserves as of that date.

	Liquids[1] (million bbls)	Bitumen (million bbls)	Synthetic Oil (million bbls)	Natural Gas (billion cubic ft)	Oil-Equivalent Basis (million bbls)
Proved Reserves					
Developed					
Consolidated Subsidiaries					
United States	1,478	—	—	15,344	4,035
Canada/South America[2]	133	519	681	1,077	1,512
Europe	361	—	—	3,516	947
Africa	1,055	—	—	711	1,174
Asia	1,306	—	—	6,593	2,405
Australia/Oceania	139	—	—	1,174	335
Total Consolidated	4,472	519	681	28,415	10,408
Equity Companies					
United States	271	—	—	97	287
Europe	21	—	—	8,167	1,382
Asia	1,623	—	—	20,494	5,039
Total Equity Company	1,915	—	—	28,758	6,708
Total Developed	6,387	519	681	57,173	17,116
Undeveloped					
Consolidated Subsidiaries					
United States	474	—	—	10,650	2,249
Canada/South America[2]	30	1,583	—	181	1,643
Europe	62	—	—	526	150
Africa	744	—	—	197	777
Asia	717	—	—	667	828
Australia/Oceania	136	—	—	6,177	1,165
Total Consolidated	2,163	1,583	—	18,398	6,812
Equity Companies					
United States	80	—	—	20	83
Europe	10	—	—	2,579	440
Asia	250	—	—	645	358
Total Equity Company	340	—	—	3,244	881
Total Undeveloped	2,503	1,583	—	21,642	7,693
Total Proved Reserves	8,890	2,102	681	78,815	24,809

(1) Liquids includes crude, condensate and natural gas liquids.

(2) South America includes developed proved reserves of 0.6 million barrels of liquids and 97 billion cubic feet of natural gas and undeveloped proved reserves of 0.6 million barrels of liquids and 66 billion cubic feet of natural gas.

In the preceding reserves information, consolidated subsidiary and equity company reserves are reported separately. However, the Corporation operates its business with the same view 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 2011-2015. 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, 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 amount recovered 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.

B. Technologies Used in Establishing Proved Reserves Additions in 2010

Additions to ExxonMobil's proved reserves in 2010 were based on estimates generated through the integration of available and appropriate geological, engineering and production data, utilizing well established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements including high-quality 2-D and 3-D seismic data, calibrated with available well control information. Where applicable, surface geological information was also utilized. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software and commercially available data analysis packages.

In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increase the quality of and confidence in the reserves estimates.

C. Qualifications of Reserves Technical Oversight Group and Internal Controls over Proved Reserves

ExxonMobil has a dedicated Reserves Technical Oversight group that is separate from the operating organization. Primary responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Commission (SEC) rules and regulations, review of annual changes in reserves estimates, and the reporting of ExxonMobil's proved reserves. This group also maintains the official company reserves estimates for ExxonMobil's proved reserves of crude and natural gas liquids, bitumen, synthetic oil and natural gas. In addition, the group provides training to personnel involved in the reserves estimation and reporting process within ExxonMobil and its affiliates. The group is managed by and staffed with individuals that have an average of more than 20 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves under the SEC guidelines. This group includes several individuals who hold advanced degrees in either Engineering or Geology, as well as individuals who hold Bachelor's degrees in various technical disciplines. Several members of the group hold professional registrations in their field of expertise and several have served on the Oil and Gas Reserves Committee of the Society of Petroleum Engineers.

The Reserves Technical Oversight group maintains a central computerized database containing the official company global reserves estimates. Appropriate controls, including limitations on database access and update capabilities, are in place to ensure data integrity within this central computerized database. An annual review of the system's controls is performed by internal audit. Key components of the reserves estimation process include technical evaluations and analysis of well and field performance and a rigorous peer review. No changes may be made to the reserves estimates in the central database, including additions of any new initial reserves estimates or subsequent revisions, unless these changes have been thoroughly reviewed and evaluated by duly authorized personnel within the operating organization. In addition, changes to reserves estimates that exceed certain thresholds require further review and approval of the appropriate level of management within the operating organization before the changes may be made in the central database. Endorsement by the Reserves Technical Oversight group for all proved reserves changes is a mandatory component of this review process. After all changes are made, reviews are held with senior management for final endorsement.

2. Proved Undeveloped Reserves

At year-end 2010, approximately 7.7 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 31 percent of the 24.8 GOEB reported in proved reserves and includes approximately 1.0 GOEB of new proved undeveloped reserves related to the acquisition of XTO. This compares to the 7.5 GOEB proved undeveloped or 33 percent of the proved reserves reported at the end of 2009. The net reduction in the percentage of proved undeveloped reserves from 2009 is reflective of our active development programs on many projects worldwide which made significant progress in converting proved undeveloped reserves into proved developed reserves in 2010. During the year, ExxonMobil completed development work in over 80 fields and participated in major project start-ups that resulted in the transfer of approximately 1.4 GOEB from proved undeveloped to proved developed reserves by year-end. This represented the movement of 18 percent of the proved undeveloped reserves into the proved developed category or an average turnover time of about five years. The largest individual transfer was associated with the completion and startup of the Ras Laffan (3) Train 7 liquefied natural gas (LNG) train in Qatar.

One of ExxonMobil's requirements for reporting proved reserves is that management has made significant funding commitments toward the development of the reserves. ExxonMobil has a disciplined investment strategy and many major fields require a long lead-time in order to be developed. Development projects typically take two to four years from the time of first recording of proved reserves to the start of production of these reserves. However, the development time for large and complex projects can exceed five years. During 2010, new approved projects added approximately 0.2 GOEB of proved undeveloped reserves. The largest of these was the Sakhalin 1 Arkutun Dagi development in Russia. Overall, investments of $19.4 billion were made by the Corporation during 2010 to progress the development of reported proved undeveloped reserves, including $16.8 billion for oil and gas producing activities and an additional $2.6 billion for other non-oil and gas producing activities such as the construction of LNG trains, tankers and regasification facilities that were undertaken to progress the development of proved undeveloped reserves. These investments represented 71 percent of the $27.3 billion in total reported Upstream capital and exploration expenditures.

Proved undeveloped reserves in Kazakhstan, Netherlands, United States, Nigeria, and Canada have remained undeveloped for five years or more primarily due to constraints on the capacity of infrastructure and the pace of co-venture/government funding, as well as the time required to complete development for very large projects. The Corporation is reasonably certain that these proved reserves will be produced; however, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance and regulatory approvals.

Approximately one third of the proved undeveloped reserves that have been reported for five or more years are in Kazakhstan and are related to two separate developments. The first is the initial development of the giant offshore Kashagan field which is included in the North Caspian Production Sharing Agreement in which ExxonMobil participates. The second is the Tengizchevroil joint venture which includes a production license in the Tengiz field and the nearby Korolev field. The joint venture is producing and proved undeveloped reserves will continue to move to proved developed as approved development phases progress.

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3. Oil and Gas Production, Production Prices and Production Costs

A. Oil and Gas Production

The table below summarizes production by final product sold and by geographic area for the last three years.

	2010	2009	2008
	(thousands of barrels daily)		
Crude oil and natural gas liquids production			
Consolidated Subsidiaries			
United States	339	311	289
Canada/South America(1)	81	82	106
Europe	330	374	423
Africa	628	685	652
Asia	326	287	319
Australia/Oceania	58	65	67
Total Consolidated Subsidiaries	1,762	1,804	1,856
Equity Companies			
United States	69	73	78
Europe	5	5	5
Asia	404	320	280
Total Equity Companies	478	398	363
Total crude oil and natural gas liquids production	2,240	2,202	2,219
Bitumen production			
Consolidated Subsidiaries			
Canada/South America	115	120	124
Synthetic oil production			
Consolidated Subsidiaries			
Canada/South America	67	65	62
Total liquids production	2,422	2,387	2,405
	(millions of cubic feet daily)		
Natural gas production available for sale			
Consolidated Subsidiaries			
United States	2,595	1,274	1,245
Canada/South America(1)	569	643	640
Europe	1,859	2,071	2,253
Africa	14	19	32
Asia	1,847	1,414	1,437
Australia/Oceania	332	315	358
Total Consolidated Subsidiaries	7,216	5,736	5,965
Equity Companies			
United States	1	1	1
Europe	1,977	1,618	1,696
Asia	2,954	1,918	1,433
Total Equity Companies	4,932	3,537	3,130
Total natural gas production available for sale	12,148	9,273	9,095
	(thousands of oil-equivalent barrels daily)		
Oil-equivalent production	4,447	3,932	3,921

(1) South America includes liquids production for 2010, 2009 and 2008 of one thousand barrels daily for each year respectively and natural gas production available for sale for 2010, 2009 and 2008 of 52 million, 58 million, and 63 million cubic feet daily for each year respectively.

B. Production Prices and Production Costs

The table below summarizes average production prices and average production costs by geographic area and by product type for the last three years.

During 2010	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
Consolidated Subsidiaries							
Average production prices							
Crude oil and NGL, per barrel	$ 70.22	$ 69.92	$ 73.37	$ 78.08	$ 72.96	$ 68.91	$ 74.04
Natural gas, per thousand cubic feet	3.92	3.41	6.44	2.15	3.19	3.31	4.31
Bitumen, per barrel	—	56.61	—	—	—	—	56.61
Synthetic oil, per barrel	—	78.42	—	—	—	—	78.42
Average production costs, per oil-equivalent barrel - total	9.92	20.07	11.62	9.63	5.65	11.20	10.54
Average production costs, per barrel - bitumen	—	17.81	—	—	—	—	17.81
Average production costs, per barrel - synthetic oil	—	42.79	—	—	—	—	42.79
Equity Companies							
Average production prices							
Crude oil and NGL, per barrel	74.70	—	74.14	—	72.67	—	72.98
Natural gas, per thousand cubic feet	8.30	—	6.91	—	5.42	—	6.02
Average production costs, per oil-equivalent barrel - total	19.11	—	2.41	—	0.98	—	2.31
Total							
Average production prices							
Crude oil and NGL, per barrel	70.98	69.92	73.38	78.08	72.80	68.91	73.81
Natural gas, per thousand cubic feet	3.92	3.41	6.68	2.15	4.56	3.31	5.00
Bitumen, per barrel	—	56.61	—	—	—	—	56.61
Synthetic oil, per barrel	—	78.42	—	—	—	—	78.42
Average production costs, per oil-equivalent barrel - total	10.67	20.07	8.46	9.63	2.91	11.20	8.14
Average production costs, per barrel - bitumen	—	17.81	—	—	—	—	17.81
Average production costs, per barrel - synthetic oil	—	42.79	—	—	—	—	42.79
During 2009							
Consolidated Subsidiaries							
Average production prices							
Crude oil and NGL, per barrel	$ 53.43	$ 54.07	$ 56.88	$ 60.10	$ 60.38	$ 54.84	$ 57.86
Natural gas, per thousand cubic feet	3.10	3.19	5.61	1.70	3.07	2.97	4.00
Bitumen, per barrel	—	45.22	—	—	—	—	45.22
Synthetic oil, per barrel	—	61.26	—	—	—	—	61.26
Average production costs, per oil-equivalent barrel - total	11.80	17.75	10.19	8.07	6.55	8.98	10.25
Average production costs, per barrel - bitumen	—	14.77	—	—	—	—	14.77
Average production costs, per barrel - synthetic oil	—	37.47	—	—	—	—	37.47
Equity Companies							
Average production prices							
Crude oil and NGL, per barrel	56.54	—	58.20	—	56.12	—	56.22
Natural gas, per thousand cubic feet	5.75	—	8.20	—	3.79	—	5.81
Average production costs, per oil-equivalent barrel - total	18.07	—	2.48	—	1.07	—	2.72
Total							
Average production prices							
Crude oil and NGL, per barrel	54.02	54.07	56.89	60.10	58.18	54.84	57.56
Natural gas, per thousand cubic feet	3.10	3.19	6.74	1.70	3.48	2.97	4.69
Bitumen, per barrel	—	45.22	—	—	—	—	45.22
Synthetic oil, per barrel	—	61.26	—	—	—	—	61.26
Average production costs, per oil-equivalent barrel - total	12.57	17.75	8.06	8.07	3.53	8.98	8.36
Average production costs, per barrel - bitumen	—	14.77	—	—	—	—	14.77
Average production costs, per barrel - synthetic oil	—	37.47	—	—	—	—	37.47

During 2008	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
Consolidated Subsidiaries							
Average production prices							
Crude oil and NGL, per barrel	$ 87.41	$ 89.46	$ 89.65	$ 92.69	$ 94.04	$ 86.08	$ 90.96
Natural gas, per thousand cubic feet	7.22	7.82	10.12	3.33	4.88	2.97	7.54
Bitumen, per barrel	—	65.45	—	—	—	—	65.45
Synthetic oil, per barrel	—	100.35	—	—	—	—	100.35
Average production costs, per oil-equivalent barrel - total	11.80	18.03	8.97	6.66	5.37	7.18	9.38
Average production costs, per barrel - bitumen	—	19.55	—	—	—	—	19.55
Average production costs, per barrel - synthetic oil	—	41.47	—	—	—	—	41.47
Equity Companies							
Average production prices							
Crude oil and NGL, per barrel	89.94	—	85.08	—	91.16	—	90.80
Natural gas, per thousand cubic feet	13.97	—	11.09	—	8.46	—	9.89
Average production costs, per oil-equivalent barrel - total	18.55	—	4.06	—	1.54	—	3.86
Total							
Average production prices							
Crude oil and NGL, per barrel	87.95	89.46	89.59	92.69	92.72	86.08	90.93
Natural gas, per thousand cubic feet	7.23	7.82	10.54	3.33	6.67	2.97	8.35
Bitumen, per barrel	—	65.45	—	—	—	—	65.45
Synthetic oil, per barrel	—	100.35	—	—	—	—	100.35
Average production costs, per oil-equivalent barrel - total	12.72	18.03	7.67	6.66	3.53	7.18	8.14
Average production costs, per barrel - bitumen	—	19.55	—	—	—	—	19.55
Average production costs, per barrel - synthetic oil	—	41.47	—	—	—	—	41.47

Average production 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 oil and gas production table in section 3.A. The volumes of natural gas used in the calculation are the production volumes of natural gas available for sale and are also shown in section 3.A. The natural gas available for sale volumes are different from those shown in the reserves table in the “Oil and Gas Reserves” part of the “Supplemental Information on Oil and Gas Exploration and Production Activities” portion of the Financial Section of this report due to volumes consumed or flared. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

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4. Drilling and Other Exploratory and Development Activities

A. Number of Net Productive and Dry Wells Drilled

	2010	2009	2008
Net Productive Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	17	10	10
Canada/South America	12	4	—
Europe	3	2	3
Africa	1	2	3
Asia	—	—	2
Australia/Oceania	2	1	—
Total Consolidated Subsidiaries	35	19	18
Equity Companies			
United States	—	—	—
Europe	2	1	1
Asia	—	—	—
Total Equity Companies	2	1	1
Total productive exploratory wells drilled	37	20	19
Net Dry Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	2	1	3
Canada/South America	1	—	—
Europe	—	4	2
Africa	1	3	2
Asia	2	1	—
Australia/Oceania	1	—	1
Total Consolidated Subsidiaries	7	9	8
Equity Companies			
United States	—	—	—
Europe	—	—	—
Asia	—	—	1
Total Equity Companies	—	—	1
Total dry exploratory wells drilled	7	9	9

	2010	2009	2008
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
United States	604	165	105
Canada/South America	229	291	223
Europe	11	10	8
Africa	60	45	39
Asia	7	9	16
Australia/Oceania	2	7	3
Total Consolidated Subsidiaries	913	527	394
Equity Companies			
United States	282	287	321
Europe	1	1	2
Asia	4	14	14
Total Equity Companies	287	302	337
Total productive development wells drilled	1,200	829	731
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	2	3	3
Canada/South America	—	—	1
Europe	—	1	—
Africa	2	—	—
Asia	—	—	—
Australia/Oceania	1	1	—
Total Consolidated Subsidiaries	5	5	4
Equity Companies			
United States	—	—	—
Europe	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total dry development wells drilled	5	5	4
Total number of net wells drilled	1,249	863	763

B. Exploratory and Development Activities Regarding Oil and Gas Resources Extracted by Mining Technologies

Syncrude Operations

Syncrude is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen, and then upgrade it to produce a high-quality, light (32 degrees API), sweet, 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. In 2010, the company's share of net production of synthetic crude oil was about 67,000 barrels per day. The Syncrude leases cover about 63 thousand acres in the Athabasca oil sands deposit.

Kearl Project

The Kearl project is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen. Imperial Oil Limited holds a 70.96 percent interest in the joint venture and ExxonMobil Canada Properties holds the other 29.04 percent. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited and a 100 percent interest in ExxonMobil Canada Properties. Kearl is comprised of six oil sands leases covering about 48 thousand acres in the Athabasca oil sands deposit.

The Kearl project is located approximately 40 miles north of Fort McMurray, Alberta, Canada. Kearl is expected to be developed in two phases. Bitumen will be extracted from oil sands produced from open-pit mining operations, and processed through a bitumen extraction and froth treatment plant. The product, a blend of bitumen and diluent, is planned to be shipped via pipelines for distribution to North American markets. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation to market by pipeline. At year-end 2010, the initial development of the Kearl project was more than 50 percent complete with expected startup in 2012.

5. Present Activities

A. Wells Drilling

	Year-end 2010		Year-end 2009	
	Gross	Net	Gross	Net
Wells Drilling				
Consolidated Subsidiaries				
United States	1,088	491	185	146
Canada/South America	92	30	83	57
Europe	27	8	20	4
Africa	54	19	24	8
Asia	98	66	20	4
Australia/Oceania	1	—	4	2
Total Consolidated Subsidiaries	1,360	614	336	221
Equity Companies				
United States	1	1	10	5
Europe	34	10	16	5
Asia	7	1	5	—
Total Equity Companies	42	12	31	10
Total gross and net wells drilling	1,402	626	367	231

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2010 acreage holdings totaled 14.8 million net acres, of which 2.2 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska. The acquisition of XTO Energy Inc. (XTO) was completed in 2010.

During 2010, 879.5 net exploration and development wells were completed in the inland lower 48 states, including development activities in the Barnett Shale of North Texas, the Freestone Trend of East Texas, the Haynesville Shale of Texas and Louisiana, the Fayetteville Shale of Arkansas, the Woodford Shale of Oklahoma, the Bakken oil play in North Dakota and Montana, the Marcellus Shale of Pennsylvania and West Virginia, the Eagle Ford Shale of South Texas, and the Piceance Basin of Colorado. Participation in Alaska production and development continued and a total of 22.2 net exploration and development wells were completed.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2010 was 2.1 million net acres. A total of 3.7 net exploration and development wells were completed during the year. The non-operated St. Malo project in the Gulf of Mexico was approved in 2010. Offshore California 1.0 net development well was completed.

The Golden Pass LNG regasification terminal in Texas commenced operations in 2010. The terminal will have the capacity to deliver up to two billion cubic feet of gas per day.

CANADA / SOUTH AMERICA

Canada

Oil and Gas Operations

ExxonMobil's year-end 2010 acreage holdings totaled 6.0 million net acres, of which 2.3 million net acres were offshore. A total of 129.0 net exploration and development wells were completed during the year. The Hibernia Southern Extension project development plan was approved in 2010.

In Situ Bitumen Operations

ExxonMobil's year-end 2010 in situ bitumen acreage holdings totaled 0.5 million net onshore acres. A total of 110.0 net development wells were completed during the year.

Argentina

ExxonMobil's net acreage totaled 0.3 million onshore acres at year-end 2010, and there were 2.0 net development wells completed during the year.

Venezuela

ExxonMobil's acreage holdings and assets were expropriated in 2007. Refer to the relevant portion of "Note 15: Litigation and Other Contingencies" of the Financial Section of this report for additional information.

EUROPE

Germany

A total of 4.8 million net onshore acres and 0.1 million net offshore acres were held by ExxonMobil at year-end 2010, with 7.3 net exploration and development wells completed during the year.

Netherlands

ExxonMobil's net interest in licenses totaled approximately 1.6 million acres at year-end 2010, of which 1.2 million acres are onshore. A total of 3.0 net exploration and development wells were completed during the year. The non-operated project to redevelop the Schoonebeek oil field was progressed.

Norway

ExxonMobil's net interest in licenses at year-end 2010 totaled approximately 0.6 million acres, all offshore. ExxonMobil participated in 3.5 net exploration and development well completions in 2010.

United Kingdom

ExxonMobil's net interest in licenses at year-end 2010 totaled approximately 0.4 million acres, all offshore. A total of 2.9 net development wells were completed during the year. The South Hook liquefied natural gas (LNG) terminal reached full capacity of two billion cubic feet per day in 2010.

AFRICA

Angola

ExxonMobil's year-end 2010 acreage holdings totaled 0.6 million net offshore acres, and 2.2 net exploration and development wells were completed during the year. The Angola Gas Gathering Project started up on-block gas handling in 2010, and project work continued on Kizomba Satellites Phase 1. On the non-operated Block 17, the Cravo-Lirio-Orquidea-Violeta project was funded in 2010, while project execution continued at Pazflor. On the non-operated Block 31, project work continued on the Plutao-Saturno-Venus-Marte project.

Chad

ExxonMobil's net year-end 2010 acreage holdings consisted of 63 thousand onshore acres with 46.0 net exploration and development wells completed during the year.

Equatorial Guinea

ExxonMobil's acreage totaled 0.1 million net offshore acres at year-end 2010, with 5.3 net development wells completed during the year.

Nigeria

ExxonMobil's net acreage totaled 1.0 million offshore acres at year-end 2010, with 9.4 net exploration and development wells completed during the year. Work continued on the deepwater Usan project in 2010. A 3-D seismic acquisition program was completed on the Nigerian Shelf joint venture acreage.

ASIA

Azerbaijan

At year-end 2010, ExxonMobil's net acreage, located in the Caspian Sea offshore of Azerbaijan, totaled 60 thousand acres. At the Azeri-Chirag-Gunashli field, 0.6 net development wells were completed. The Chirag Oil Project was funded in 2010, and project activities are under way.

Indonesia

At year-end 2010, ExxonMobil had 4.4 million net acres, 3.3 million net acres offshore and 1.1 million net acres onshore. A total of 0.8 net exploration wells were completed during the year.

Iraq

At year-end 2010, ExxonMobil's onshore acreage was 87 thousand net acres. During 2010, a contract was signed with South Oil Company of the Iraqi Ministry of Oil to redevelop and expand the West Qurna (Phase 1) oil field. The term of the contract is 20 years with the right to extend for five years. In 2010 initial field rehabilitation activities commenced. Field rehabilitation activities across the life of this project will include drilling of new wells, working over of existing wells, optimization and debottlenecking of existing facilities, and the establishment of field offices and camps.

Kazakhstan

ExxonMobil's net acreage totaled 0.1 million acres onshore and 0.2 million acres offshore at year-end 2010, with 0.2 net development wells completed during 2010. Working with our partners, construction of the initial phase of the Kashagan field continued during 2010.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.5 million net acres offshore Malaysia at year-end 2010. During the year, a total of 5.1 net exploration and development wells were completed.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil's net acreage totaled 60 thousand acres offshore at year-end 2010. Following the startup of RasGas Train 7 during 2010, ExxonMobil participated in 61.8 million tonnes per year gross liquefied natural gas (LNG) capacity at year end.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 10 thousand acres onshore at year-end 2010.

Russia

ExxonMobil's net acreage holdings at year-end 2010 were 85 thousand acres, all offshore. A total of 1.5 net development wells were completed at the Sakhalin-1 Odoptu field during the year which started production in 2010. The Sakhalin-1 Chayvo Expansion and Arkutun-Dagi projects were both funded in 2010, and project activities are under way.

Thailand

ExxonMobil's net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2010.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year end 2010. During the year, 0.6 net development wells were completed, as rig activity focused mainly on workovers and injection wells.

ExxonMobil's net acreage in the Abu Dhabi onshore oil concession was 0.5 million acres at year-end 2010, of which 0.4 million acres are onshore. During the year, a total of 4.3 net development wells were completed.

AUSTRALIA/OCEANIA

Australia

ExxonMobil's net year-end 2010 offshore acreage holdings totaled 1.7 million acres. During 2010, a total of 5.3 net exploration and development wells were drilled. Offshore installation commenced for the Kipper Tuna Turrum project.

Project construction activity for the co-venturer operated Gorgon liquefied natural gas (LNG) project progressed in 2010. The project consists of a subsea infrastructure for offshore production and transportation of the gas, and a 15 million tonnes per year LNG facility and a 280 million cubic feet per day domestic gas plant located on Barrow Island, Western Australia.

Papua New Guinea

A total of 0.4 million net onshore acres were held by ExxonMobil at year-end 2010, with 0.4 net development wells completed during the year. In 2010, the Papua New Guinea liquefied natural gas project commenced construction activities. The project consists of conditioning facilities in the southern PNG Highlands, a 6.6 million tonnes per year LNG facility near Port Moresby and approximately 450 miles of onshore and offshore pipelines.

WORLDWIDE EXPLORATION

At year-end 2010, exploration activities were under way in several areas in which ExxonMobil has no established production operations and thus are not included above. A total of 40.6 million net acres were held at year-end 2010, and 2.6 net exploration wells were completed during the year in these countries.

6. Delivery Commitments

ExxonMobil sells crude oil and natural gas from its producing operations under a variety of contractual obligations, some of which may specify the delivery of a fixed and determinable quantity for periods longer than one year. ExxonMobil also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be a combination of our own production and the spot market. Worldwide, we are contractually committed to deliver approximately 17 million barrels of crude oil and 3,900 billion cubic feet of natural gas for the period from 2011 through 2013. We expect to fulfill the majority of these delivery commitments with production from our proved developed reserves. Any remaining commitments will be fulfilled with production from our proved undeveloped reserves and spot market purchases as necessary.

7. Oil and Gas Properties, Wells, Operations and Acreage

A. Gross and Net Productive Wells

	Year-end 2010				Year-end 2009			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	23,789	8,076	36,189	21,429	15,606	4,821	9,261	5,645
Canada/South America	5,609	5,092	6,650	3,361	5,357	4,828	6,728	3,408
Europe	1,438	395	672	291	1,395	389	649	292
Africa	1,126	454	14	6	1,081	432	13	5
Asia	845	411	207	173	751	352	197	162
Australia/Oceania	687	163	27	13	722	170	41	21
Total Consolidated Subsidiaries	33,494	14,591	43,759	25,273	24,912	10,992	16,889	9,533
Equity Companies								
United States	11,270	5,295	7	3	11,592	5,452	8	4
Europe	28	14	594	194	27	14	576	187
Asia	883	99	121	30	873	98	126	36
Total Equity Companies	12,181	5,408	722	227	12,492	5,564	710	227
Total gross and net productive wells	45,675	19,999	44,481	25,500	37,404	16,556	17,599	9,760

There were 35,691 gross and 30,494 net operated wells at year-end 2010 and 16,587 gross and 13,737 net operated wells at year-end 2009. The number of wells with multiple completions was 1,725 gross in 2010 and 1,039 gross in 2009.

B. Gross and Net Developed Acreage

	Year-end 2010		Year-end 2009	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	16,621	9,861	9,866	5,061
Canada/South America(1)	5,450	2,439	5,570	2,460
Europe	3,956	1,630	5,359	2,454
Africa	1,772	684	1,958	758
Asia	1,411	623	1,226	512
Australia/Oceania	1,955	719	1,956	719
Total Consolidated Subsidiaries	31,165	15,956	25,935	11,964
Equity Companies				
United States	137	58	165	59
Europe	4,363	1,356	4,325	1,352
Asia	5,818	648	5,817	648
Total Equity Companies	10,318	2,062	10,307	2,059
Total gross and net developed acreage	41,483	18,018	36,242	14,023

(1) Includes gross and net developed acreage in South America of 618 gross and 202 net thousands of acres for 2010 and 618 gross and 202 net thousands of acres for 2009.

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

C. Gross and Net Undeveloped Acreage

	Year-end 2010		Year-end 2009	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	8,393	4,845	7,650	5,034
Canada/South America[(1)]	20,612	11,977	26,074	17,107
Europe	34,787	16,118	25,420	13,462
Africa	14,733	8,612	15,768	10,555
Asia	24,203	19,086	25,568	20,400
Australia/Oceania	4,966	1,352	9,780	5,216
Total Consolidated Subsidiaries	107,694	61,990	110,260	71,774
Equity Companies				
United States	188	69	208	77
Europe	—	—	53	8
Asia	—	—	228	57
Total Equity Companies	188	69	489	142
Total gross and net undeveloped acreage	107,882	62,059	110,749	71,916

(1) Includes gross and net undeveloped acreage in South America of 10,111 gross and 7,442 net thousands of acres for 2010 and 12,005 gross and 11,800 net thousands of acres for 2009.

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. The scheduled expiration of leases and concessions for undeveloped acreage over the next three years is not expected to have a material adverse impact on the Corporation.

D. Summary of Acreage Terms

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. Under certain circumstances, a lease may be held beyond its exploration term even if production has not commenced. In some instances, a “fee interest” is acquired where both the surface and the underlying mineral interests are owned outright.

CANADA / SOUTH AMERICA

Canada

Exploration permits are granted for varying periods of time with renewals possible. Exploration rights in onshore areas acquired from Canadian provinces entitle the holder to obtain leases upon completing specified work. In general, production leases are held as long as there is production on the lease. The majority of Cold Lake leases are held in this manner. The exploration acreage in eastern Canada and the block in the Beaufort Sea acquired in 2007 are currently held by work commitments of various amounts.

Argentina

The federal 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. Argentine provinces are entitled to modify the concession terms granted within their territories. The exploration permit granted by Neuquen Province to an ExxonMobil affiliate in 2010 fixed the initial exploration period at three years, the second at two years and the third at one year, and one of these periods can be extended for an additional year.

EUROPE

Germany

Exploration concessions are granted for an initial maximum period of five years, with an unlimited number of extensions of up to three years each. 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. In 2007, ExxonMobil affiliates acquired four exploration licenses in the state of Lower Saxony. The exploration licenses are for a period of five years during which exploration work programs will be carried out. In 2009, ExxonMobil affiliates acquired two exploration licenses in the state of North Rhine Westphalia for an initial period of five years and an extension to one of the Lower Saxony licenses.

Netherlands

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

Production rights granted prior to January 1, 2003, remain subject to their existing terms, and differ slightly for onshore and offshore areas. Onshore production licenses issued prior to 1988 were indefinite; from 1988 they were issued for a period as explicitly defined in the license, ranging from 35 to 45 years. Offshore production licenses issued before 1976 were issued for a fixed period of 40 years; from 1976 they were again issued for a period as explicitly defined in the license, ranging from 15 to 40 years.

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. At the end of any such 40-year term, licenses may continue in producing areas until cessation of production; or licenses may continue in development areas for periods agreed on a case-by-case basis until they become producing areas; or licenses terminate in all other areas. The licensing regime was last updated in 2002, and the majority of licenses issued have an initial term of four years with a second term extension of four years and a final term of 18 years with a mandatory relinquishment of 50 percent of the 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.

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, Industry 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. A new Hydrocarbons Law was enacted in November 2006. Under the new law, the exploration terms for new production sharing contracts are four to five years with a maximum of two one-year extensions, unless the Ministry agrees otherwise.

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 have been renewed, effective December 1, 2008, for a further period of 20 years, with a further renewal option of 20 years. Operations under these pre-1969 OMLs are conducted under a joint venture agreement with NNPC rather than a PSC. In 2000, a Memorandum of Understanding (MOU) was executed defining commercial terms applicable to existing joint venture oil production. The MOU may be terminated on one calendar year's notice.

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.

ASIA

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.

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.

Iraq

Development and production activities in the state-owned oil and gas fields are governed by contracts with regional oil companies of the Iraq Ministry of Oil. An ExxonMobil affiliate entered into a contract with South Oil Company of the Ministry of Iraq for the rights to participate in the development and production activities of the West Qurna (Phase I) oil and gas field effective March 1, 2010. The term of the contract is 20 years with the right to extend for 5 years.

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 followed by separate appraisal periods for each discovery. The production period for each discovery, which includes development, is for 20 years from the date of declaration of commerciality with the possibility of two ten-year extensions.

Malaysia

Exploration and production activities are governed by production sharing contracts (PSCs) negotiated with the national oil company. The more recent PSCs governing exploration and production activities have an overall term of 24 to 38 years, depending on water depth, 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.

In 2008, the Company reached agreement with the national oil company for a new PSC, which was subsequently signed in 2009. Under the new PSC, from 2008 until March 31, 2012, the Company is entitled to undertake new development and production activities in oil fields under an existing PSC, subject to new minimum work and spending commitments, including an enhanced oil recovery project in one of the oil fields. When the existing PSC expires on March 31, 2012, the producing fields covered by the existing PSC will automatically become part of the new PSC, which has a 25-year duration from April 2008.

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

The Jannah production sharing agreement has a development period extending 20 years from first commercial declaration, which was made in June 1995.

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.

Thailand

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

United Arab Emirates

Exploration and production activities for the major onshore oil fields 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. An interest in the Upper Zakum field, a major offshore field, was acquired effective as of January 2006, for a term expiring March 2026.

AUSTRALIA/OCEANIA

Australia

Exploration and production activities conducted offshore in Commonwealth waters are governed by Federal legislation. Exploration permits are granted for an initial term of six years with two possible five-year renewal periods. 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 July 1998, production licenses were granted initially for 21 years, with a further renewal of 21 years and thereafter "indefinitely", i.e., for the life of the field. Effective from July 1998, new production licenses are granted "indefinitely". In each case, a production license may be terminated if no production operations have been carried on for five years.

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 within the maximum possible retention time of 15 years. Petroleum Retention licenses are granted for five-year terms, and may be extended, at the Minister's discretion, twice for the maximum retention time of 15 years. Extensions of Petroleum Retention licenses may be for periods of less than one year, renewable annually, if the Minister considers at the time of extension that the resources could become commercially viable in less than five years.

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Information with regard to the Downstream segment follows:

ExxonMobil's Downstream segment manufactures and sells petroleum products. The refining and supply operations encompass a global network of manufacturing plants, transportation systems, and distribution centers that provide a range of fuels, lubricants and other products and feedstocks to our customers around the world.

Refining Capacity At Year-End 2010 [1]

		ExxonMobil Share KBD [2]	ExxonMobil Interest %
United States			
Torrance	California	150	100
Joliet	Illinois	238	100
Baton Rouge	Louisiana	504	100
Baytown	Texas	561	100
Beaumont	Texas	345	100
Other (2 refineries)		155	
Total United States		1,953	
Canada			
Strathcona	Alberta	189	69.6
Dartmouth	Nova Scotia	83	69.6
Nanticoke	Ontario	113	69.6
Sarnia	Ontario	121	69.6
Total Canada		506	
Europe			
Antwerp	Belgium	307	100
Fos-sur-Mer	France	119	82.9
Port-Jerome-Gravenchon	France	233	82.9
Karlsruhe	Germany	78	25
Augusta	Italy	198	100
Trecate	Italy	174	74.1
Rotterdam	Netherlands	191	100
Slagen	Norway	116	100
Fawley	United Kingdom	329	100
Total Europe		1,745	
Asia Pacific			
Kawasaki	Japan	296	50.1
Sakai	Japan	139	50.1
Wakayama	Japan	160	50.1
Jurong/PAC	Singapore	605	100
Sriracha	Thailand	174	66
Other (5 refineries)		337	
Total Asia Pacific		1,711	
Other Non-U.S.			
Yanbu	Saudi Arabia	200	50
Laffan	Qatar	14	10
Other (4 refineries)		131	
Total Other Non-U.S.		345	
Total Worldwide		6,260	

(1) Capacity data is based on 100 percent of rated refinery process unit stream-day capacities under normal operating conditions, less the impact of shutdowns for regular repair and maintenance activities, averaged over an extended period of time.

(2) Thousands of barrels per day (KBD). ExxonMobil share reflects 100 percent of atmospheric distillation capacity in operations of ExxonMobil and majority-owned subsidiaries. For companies owned 50 percent or less, ExxonMobil share is the greater of ExxonMobil's equity interest or that portion of distillation capacity normally available to ExxonMobil.

The marketing operations sell products and services throughout the world. Our *Exxon*, *Esso* and *Mobil* brands serve customers at over 26,000 retail service stations.

Retail Sites Year-End 2010

United States	
Owned/leased	1,243
Distributors/resellers	8,520
Total United States	9,763
Canada	
Owned/leased	500
Distributors/resellers	1,349
Total Canada	1,849
Europe	
Owned/leased	3,965
Distributors/resellers	2,584
Total Europe	6,549
Asia Pacific	
Owned/leased	1,963
Distributors/resellers	3,631
Total Asia Pacific	5,594
Latin America	
Owned/leased	567
Distributors/resellers	1,329
Total Latin America	1,896
Middle East/Africa	
Owned/leased	472
Distributors/resellers	155
Total Middle East/Africa	627
Worldwide	
Owned/leased	8,710
Distributors/resellers	17,568
Total worldwide	26,278

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Information with regard to the Chemical segment follows:

ExxonMobil's Chemical segment manufactures and sells petrochemicals. The Chemical business supplies olefins, polyolefins, aromatics, and a wide variety of other petrochemicals.

Chemical Complex Capacity at Year-End 2010 (1)(2)

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest %
North America						
Baton Rouge	Louisiana	1.0	1.3	0.4	—	100
Baytown	Texas	2.2	—	0.8	0.6	100
Beaumont	Texas	0.8	1.0	—	0.3	100
Mont Belvieu	Texas	—	1.0	—	—	100
Sarnia	Ontario	0.3	0.5	—	—	69.6
Total North America		4.3	3.8	1.2	0.9	
Europe						
Antwerp	Belgium	0.5	0.4	—	—	35(3)
Fife	United Kingdom	0.4	—	—	—	50
Meerhout	Belgium	—	0.5	—	—	100
Notre-Dame-de-Gravenchon	France	0.4	0.4	0.3	—	100
Rotterdam	Netherlands	—	—	—	0.7	100
Total Europe		1.3	1.3	0.3	0.7	
Middle East						
Al Jubail	Saudi Arabia	0.6	0.6	—	—	50
Yanbu	Saudi Arabia	1.0	0.7	0.2	—	50
Total Middle East		1.6	1.3	0.2	—	
Asia Pacific						
Fujian	China	0.2	0.2	0.1	0.2	25
Kawasaki	Japan	0.5	0.1	—	—	50
Singapore	Singapore	0.9	0.6	0.4	0.9	100
Sriracha	Thailand	—	—	—	0.5	66
Total Asia Pacific		1.6	0.9	0.5	1.6	
All Other		—	—	—	0.6	
Total Worldwide		8.8	7.3	2.2	3.8	

(1) Capacity for ethylene, polyethylene, polypropylene and paraxylene in millions of metric tons per year.

(2) Capacity reflects 100 percent for operations of ExxonMobil and majority-owned subsidiaries. For companies owned 50 percent or less, capacity is ExxonMobil's interest.

(3) Net ExxonMobil ethylene capacity is 35%. Net ExxonMobil polyethylene capacity is 100%.

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

Regarding a matter previously reported in the Corporation's Form 10-Q for the second quarter of 2010, ExxonMobil Oil Corporation's Beaumont, Texas refinery entered into an Agreed Order with the Texas Commission on Environmental Quality on November 15, 2010 and paid a civil penalty of $106 thousand to resolve Notices of Violation issued in January and February 2010 relating to six alleged violations of air emission regulations.

With regard to the matter most recently reported in the Corporation's Form 10-Q for the second quarter of 2007, the New York State Attorney General, Exxon Mobil Corporation and ExxonMobil Oil Corporation have agreed to enter into a Consent Decree to resolve issues relating to alleged contamination at ExxonMobil's former Brooklyn, New York terminal and refinery. The Consent Decree was lodged in the U.S. District Court for the Eastern District of New York on November 17, 2010 and was subject to public comment until January 25, 2011. On January 24, 2011, the United States Department of Justice filed the only comments, which sought clarification of some elements of the Consent Decree. Those comments have been incorporated into the Consent Decree, which is subject to review and approval by the Court. If approved, the Consent Decree would require ExxonMobil to undertake actions to investigate and remediate certain environmental conditions at the Brooklyn terminal and refinery, pay $19.5 million to fund Environmental Benefit Projects to benefit the Greenpoint Community; pay a civil penalty of $250 thousand; pay $250 thousand for Natural Resources Damages Restoration Projects; pay past costs of the State for oversight of, investigation and remedial activities in the amount of $1.5 million and pay future State oversight costs, up to $3.5 million.

On November 29, 2010, XTO Energy Inc. received a Notice of Violation (NOV) from the Pennsylvania Department of Environmental Protection (PaDEP) alleging that an unpermitted discharge of brine or produced fluid occurred from a tank located at the Marquardt Well Site in Penn Township, Pennsylvania, which discharge reached a water of the State and that XTO failed to notify the PaDEP of the incident, had litter on the site, and failed to post well permit numbers and operator information at the well site. The NOV does not contain a specific penalty demand, but XTO believes that PaDEP may seek a penalty in excess of $100 thousand. XTO responded to the NOV on December 9, 2010 and, while not admitting to a violation for the alleged release, agreed to cooperate with PaDEP in responding to and remediating it.

As reported in the Corporation's 2009 Form 10-K, in October 2009, a purported shareholder complaint captioned *Resnik v. Boskin et al.*, alleging direct and derivative claims, was filed in the United States District Court for the District of New Jersey, naming the directors serving at the time, the "named executive officers" listed in the Corporation's 2009 Proxy Statement (as defined in Securities and Exchange Commission regulations) and ExxonMobil as defendants. The complaint was amended in December 2009, alleging that the defendants made materially false or misleading proxy solicitations in connection with the 2008 and 2009 shareholder votes regarding the election of directors and failed to seek stockholder reapproval of the Exxon Mobil Corporation 2003 Incentive Program to qualify certain incentive compensation paid to the named executive officers as properly deductible expenditures. The amended complaint seeks various injunctive remedies, including corrective disclosure, new election of directors after corrective disclosure, enjoining candidates from serving on the Board until a new election occurs, stockholder reapproval of the program, enjoining payments under the program and short term incentive program to the named executive officers, damages (the amount of which is not specified) from the individual defendants in favor of ExxonMobil, and costs and expenses of the action. The defendants moved to dismiss the lawsuit on several grounds, including that the plaintiff's allegations concerning the Corporation's proxy solicitations do not state claims under the federal securities laws and that the plaintiff's derivative claims cannot stand since the plaintiff failed to make a demand on the Corporation or allege facts that would excuse a demand. The motion was argued to the district court in August 2010. On February 17, 2011, the court granted defendants' motion to dismiss, finding fatal flaws in the plaintiff's three causes of action. Notably, the court determined that

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the Internal Revenue Code and Treasury Regulations did not require the Corporation to seek stockholder reapproval of its incentive programs at the time it distributed the 2008 and 2009 proxy statements. Notwithstanding the plaintiff's dismissal, the court granted the plaintiff 21 days to amend the three causes of action. If the plaintiff does not timely amend, plaintiff will have 30 days thereafter to file a notice of appeal.

Refer to the relevant portions of "Note 15: Litigation and Other Contingencies" of the Financial Section of this report for additional information on legal proceedings.

Executive Officers of the Registrant [pursuant to Instruction 3 to Regulation S-K, Item 401(b)]
(ages as of March 1, 2011).

Rex W. Tillerson	*Chairman of the Board*	
Held current title since:	January 1, 2006	Age: 58

Mr. Rex W. Tillerson became a Director and President of Exxon Mobil Corporation on March 1, 2004. He became Chairman of the Board and Chief Executive Officer on January 1, 2006. He still holds these positions as of this filing date.

Mark W. Albers	*Senior Vice President*	
Held current title since:	April 1, 2007	Age: 54

Mr. Mark W. Albers was President of ExxonMobil Development Company October 1, 2004 – April 13, 2007. He became Senior Vice President of Exxon Mobil Corporation on April 1, 2007, a position he still holds as of this filing date.

Michael J. Dolan	*Senior Vice President*	
Held current title since:	April 1, 2008	Age: 57

Mr. Michael J. Dolan was President of ExxonMobil Chemical Company September 1, 2004 – March 31, 2008. He was Vice President of Exxon Mobil Corporation September 1, 2004 – March 31, 2008. He became Senior Vice President of Exxon Mobil Corporation on April 1, 2008, a position he still holds as of this filing date.

Donald D. Humphreys	*Senior Vice President and Treasurer*	
Held current title since:	January 25, 2006 (Senior Vice President) July 1, 2004 (Treasurer)	Age: 63

Mr. Donald D. Humphreys was Vice President and Controller of Exxon Mobil Corporation (formerly Exxon Corporation) July 1, 1997 – June 30, 2004. He was the Vice President and Treasurer of Exxon Mobil Corporation July 1, 2004 – January 24, 2006. He became Senior Vice President and Treasurer of Exxon Mobil Corporation on January 25, 2006, positions he still holds as of this filing date.

Andrew P. Swiger	*Senior Vice President*	
Held current title since:	April 1, 2009	Age: 54

Mr. Andrew P. Swiger was Executive Vice President of ExxonMobil Production Company May 1, 2004 – September 30, 2006. He was President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation October 1, 2006 – March 31, 2009. He became Senior Vice President of Exxon Mobil Corporation on April 1, 2009, a position he still holds as of this filing date.

S. Jack Balagia	*Vice President and General Counsel*	
Held current title since:	March 1, 2010	Age: 59

Mr. S. Jack Balagia was Assistant General Counsel of Exxon Mobil Corporation April 1, 2004 to March 1, 2010. He became Vice President and General Counsel of Exxon Mobil Corporation on March 1, 2010, a position he still holds as of this filing date.

William M. Colton	*Vice President - Strategic Planning*	
Held current title since:	February 1, 2009	Age: 57

Mr. William M. Colton was Assistant Treasurer of Exxon Mobil Corporation January 25, 2006 to January 31, 2009. He became Vice President—Strategic Planning of Exxon Mobil Corporation on February 1, 2009, a position he still holds as of this filing date.

Harold R. Cramer	*Vice President*	
Held current title since:	November 30, 1999	Age: 60

Mr. Harold R. Cramer became President of ExxonMobil Fuels Marketing Company and Vice President of Exxon Mobil Corporation on November 30, 1999, positions he still holds as of this filing date.

Neil W. Duffin	*President, ExxonMobil Development Company*	
Held current title since:	April 13, 2007	Age: 54

Mr. Neil W. Duffin was Vice President of ExxonMobil Production Company July 1, 2004 – August 31, 2006. He was Executive Vice President of ExxonMobil Development Company September 1, 2006 – April 13, 2007, becoming President on April 13, 2007, a position he still holds as of this filing date.

Robert S. Franklin	*Vice President*	
Held current title since:	May 1, 2009	Age: 53

Mr. Robert S. Franklin was Vice President, New Business Development of ExxonMobil Gas & Power Marketing Company July 1, 2001 – April 15, 2007. He was Executive Assistant to the Chairman, Exxon Mobil Corporation April 16, 2007 – March 31, 2008. He was Vice President, Europe/Russia/Caspian of ExxonMobil Production Company April 1, 2008 – May 1, 2009. He became Vice President of Exxon Mobil Corporation and President, ExxonMobil Upstream Ventures on May 1, 2009, positions he still holds as of this filing date.

Sherman J. Glass, Jr.	*Vice President*	
Held current title since:	April 1, 2008	Age: 63

Mr. Sherman J. Glass, Jr. was Senior Vice President of ExxonMobil Chemical Company September 1, 2005 – March 31, 2008. He became President of ExxonMobil Refining & Supply Company and Vice President of Exxon Mobil Corporation on April 1, 2008. He still holds these positions as of this filing date.

Stephen M. Greenlee	*Vice President*	
Held current title since:	September 1, 2010	Age: 53

Mr. Stephen M. Greenlee was Vice President of ExxonMobil Exploration Company June 1, 2004 – June 1, 2009. He was President of ExxonMobil Upstream Research Company June 1, 2009 – August 31, 2010. He became President of ExxonMobil Exploration Company and Vice President of Exxon Mobil Corporation on September 1, 2010, positions he still holds as of this filing date.

Alan J. Kelly	*Vice President*	
Held current title since:	December 1, 2007	Age: 53

Mr. Alan J. Kelly was Manager, Global Logistics of ExxonMobil Refining & Supply Company February 1, 2005 – February 28, 2006. He was on Special Assignment for the National Petroleum Council March 1, 2006 – November 30, 2007. He became President of ExxonMobil Lubricants & Petroleum Specialties Company and Vice President of Exxon Mobil Corporation on December 1, 2007. He still holds these positions as of this filing date.

Richard M. Kruger	*Vice President*	
Held current title since:	April 1, 2008	Age: 51

Mr. Richard M. Kruger was Vice President of ExxonMobil Production Company January 1, 2003 – September 30, 2006, and then Executive Vice President October 1, 2006 – March 31, 2008. He became President of ExxonMobil Production Company and Vice President of Exxon Mobil Corporation on April 1, 2008. He still holds these positions as of this filing date.

Patrick T. Mulva	*Vice President and Controller*	
Held current title since:	February 1, 2002 (Vice President) July 1, 2004 (Controller)	Age: 59

Mr. Patrick T. Mulva was Vice President—Investor Relations and Secretary of Exxon Mobil Corporation February 1, 2002 – July 1, 2004. On July 1, 2004, he became Vice President and Controller, positions he still holds as of this filing date.

Stephen D. Pryor	*Vice President*	
Held current title since:	December 1, 2004	Age: 61

Mr. Stephen D. Pryor was President of ExxonMobil Refining & Supply Company and Vice President of Exxon Mobil Corporation December 1, 2004 – March 31, 2008. He became President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation on April 1, 2008, positions he still holds as of this filing date.

David S. Rosenthal	*Vice President - Investor Relations and Secretary*	
Held current title since:	October 1, 2008	Age: 54

Mr. David S. Rosenthal was Controller of ExxonMobil Production Company April 1, 2002 – May 31, 2006. He was Assistant Controller of Exxon Mobil Corporation on June 1, 2006 – September 30, 2008. He became Vice President—Investor Relations and Secretary of Exxon Mobil Corporation on October 1, 2008, positions he still holds as of this filing date.

James M. Spellings, Jr.	*Vice President and General Tax Counsel*	
Held current title since:	March 1, 2010	Age: 49

Mr. James M. Spellings, Jr. was General Manager—Corporate Planning of Exxon Mobil Corporation February 1, 2005 – March 31, 2007, and then Associate General Tax Counsel April 1, 2007 – March 1, 2010. He became Vice President and General Tax Counsel on March 1, 2010, positions he still holds as of this filing date.

Thomas R. Walters	*Vice President*	
Held current title since:	April 1, 2009	Age: 56

Mr. Thomas R. Walters was President of Global Services Company from September 1, 2005 – April 4, 2007. He was Executive Vice President of ExxonMobil Development Company April 13, 2007 – April 1, 2009. He became President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation on April 1, 2009, positions he still holds as of this filing date.

Jack P. Williams, Jr.	*President, XTO Energy Inc.*	
Held current title since:	June 25, 2010	Age: 47

Mr. Jack P. Williams, Jr. was Upstream Advisor, Exxon Mobil Corporation July 1, 2005 – May 1, 2007. He was Vice President, Engineering, ExxonMobil Production Company May 1, 2007 – April 30, 2009. He was Vice President of ExxonMobil Development Company May 1, 2009 – July 1, 2010. He became President of XTO Energy Inc. on June 25, 2010, a position he still holds as of this filing date.

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" portion of the Financial Section of this report.

Issuer Purchases of Equity Securities for Quarter Ended December 31, 2010

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, 2010	27,460,538	65.07	27,460,538	
November, 2010	26,123,594	69.57	26,123,594	
December, 2010	29,589,368	72.82	29,589,368	
Total	83,173,500	69.24	83,173,500	(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. Repurchases were temporarily suspended due to regulatory requirements in connection with the XTO transaction. The Corporation has continued to purchase shares since this announcement and to report purchased volumes in its quarterly earnings releases. In its most recent earnings release dated January 31, 2011, the Corporation stated that first quarter 2011 share purchases are continuing at a pace consistent with fourth quarter 2010 share reduction spending of $5 billion. 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.

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

	Years Ended December 31,				
	2010 (1)	2009	2008	2007	2006
	(millions of dollars, except per share amounts)				
Sales and other operating revenue (2)	$370,125	$301,500	$459,579	$390,328	$365,467
(2) Sales-based taxes included.	*$ 28,547*	*$ 25,936*	*$ 34,508*	*$ 31,728*	*$ 30,381*
Net income attributable to ExxonMobil	$ 30,460	$ 19,280	$ 45,220	$ 40,610	$ 39,500
Earnings per common share	$ 6.24	$ 3.99	$ 8.70	$ 7.31	$ 6.64
Earnings per common share - assuming dilution	$ 6.22	$ 3.98	$ 8.66	$ 7.26	$ 6.60
Cash dividends per common share	$ 1.74	$ 1.66	$ 1.55	$ 1.37	$ 1.28
Total assets	$302,510	$233,323	$228,052	$242,082	$219,015
Long-term debt	$ 12,227	$ 7,129	$ 7,025	$ 7,183	$ 6,645

(1) See Note 19: Acquisition of XTO Energy Inc. contained in the Financial Section of this report.

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" in 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", excluding the part entitled "Inflation and Other Uncertainties," in 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 25, 2011, beginning with the section entitled "Report of Independent Registered Public Accounting Firm" and continuing through "Note 19: Acquisition of XTO Energy Inc.";
- "Quarterly Information" (unaudited);
- "Supplemental Information on Oil and Gas Exploration and Production Activities" (unaudited); and
- "Frequently Used Terms" (unaudited).

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, 2010. Based on that evaluation, these officers have concluded that the Corporation's disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Corporation in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

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 criteria established in 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, 2010.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2010, as stated in their report included in 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*.

Effective April 1, 2011, the annual salary for Michael J. Dolan will increase to $1,010,000. Like all other ExxonMobil executive officers, Mr. Dolan is an "at will" employee of the Corporation and does not have an employment contract.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

Incorporated by reference to the following from the registrant's definitive proxy statement for the 2011 annual meeting of shareholders (the "2011 Proxy Statement"):

- The section entitled "Election of Directors";
- The portion entitled "Section 16(a) Beneficial Ownership Reporting Compliance" of the section entitled "Director and Executive Officer Stock Ownership";
- The portions entitled "Director Qualifications" and "Code of Ethics and Business Conduct" of the section entitled "Corporate Governance"; and
- The "Audit Committee" portion and the membership table of the portion entitled "Board Meetings and Committees; Annual Meeting Attendance" of the section entitled "Corporate Governance".

Item 11. *Executive Compensation.*

Incorporated by reference to the sections entitled "Director Compensation," "Compensation Committee Report," "Compensation Discussion and Analysis" and "Executive Compensation Tables" of the registrant's 2011 Proxy Statement.

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

The information required under Item 403 of Regulation S-K is incorporated by reference to the sections "Director and Executive Officer Stock Ownership" and "Certain Beneficial Owners" of the registrant's 2011 Proxy Statement.

Equity Compensation Plan Information

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (1)	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	29,111,877(2)(3)	$37.12	142,681,756(3)(4)(5)
Equity compensation plans not approved by security holders	0	0	0
Total	29,111,877	$37.12	142,681,756

(1) The exercise price of each option reflected in this table is equal to the fair market value of the Company's common stock on the date the option was granted. The weighted-average price reflects one prior option grant that is still outstanding.

(2) Includes 19,578,656 options granted under the 1993 Incentive Program and 9,533,221 restricted stock units to be settled in shares.

(3) Does not include options that ExxonMobil assumed in the 2010 merger with XTO Energy Inc. At year-end 2010, the number of securities to be issued upon exercise of outstanding options under XTO Energy Inc. plans was 9,929,860, and the weighted-average exercise price of such options was $59.51. No additional awards may be made under those plans.

(4) Available shares can be granted in the form of restricted stock, options, or other stock-based awards. Includes 141,939,056 shares available for award under the 2003 Incentive Program and 742,700 shares available for award under the 2004 Non-Employee Director Restricted Stock Plan.

(5) Under the 2004 Non-Employee Director Restricted Stock Plan approved by shareholders in May 2004, and the related standing resolution adopted by the Board, each non-employee director automatically receives 8,000 shares of restricted stock when first elected to the Board and, if the director remains in office, an additional 2,500 restricted shares each following year. While on the Board, each non-employee director receives the same cash dividends on restricted shares as a holder of regular common stock, but the director is not allowed to sell the shares. The restricted shares may be forfeited if the director leaves the Board early.

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

Information provided in response to this Item 13 is incorporated by reference to the portions entitled "Related Person Transactions and Procedures" and "Director Independence" of the section entitled "Corporate Governance" of the registrant's 2011 Proxy Statement.

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

Incorporated by reference to the portion entitled "Audit Committee" of the section entitled "Corporate Governance" and the section entitled "Ratification of Independent Auditors" of the registrant's 2011 Proxy Statement.

PART IV

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

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

(a) (3) Exhibits:
See Index to Exhibits of this report.

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FINANCIAL SECTION

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BUSINESS PROFILE

Financial	Earnings After Income Taxes 2010	Earnings After Income Taxes 2009	Average Capital Employed 2010	Average Capital Employed 2009	Return on Average Capital Employed 2010	Return on Average Capital Employed 2009	Capital and Exploration Expenditures 2010	Capital and Exploration Expenditures 2009
	(millions of dollars)				(percent)		(millions of dollars)	
Upstream								
United States	$ 4,272	$ 2,893	$ 34,969	$ 15,865	12.2	18.2	$ 6,349	$ 3,585
Non-U.S.	19,825	14,214	68,318	57,336	29.0	24.8	20,970	17,119
Total	$24,097	$17,107	$103,287	$ 73,201	23.3	23.4	$27,319	$20,704
Downstream								
United States	$ 770	$ (153)	$ 6,154	$ 7,306	12.5	(2.1)	$ 982	$ 1,511
Non-U.S.	2,797	1,934	17,976	17,793	15.6	10.9	1,523	1,685
Total	$ 3,567	$ 1,781	$ 24,130	$ 25,099	14.8	7.1	$ 2,505	$ 3,196
Chemical								
United States	$ 2,422	$ 769	$ 4,566	$ 4,370	53.0	17.6	$ 279	$ 319
Non-U.S.	2,491	1,540	14,114	12,190	17.6	12.6	1,936	2,829
Total	$ 4,913	$ 2,309	$ 18,680	$ 16,560	26.3	13.9	$ 2,215	$ 3,148
Corporate and financing	(2,117)	(1,917)	(880)	10,190	—	—	187	44
Total	$30,460	$19,280	$145,217	$125,050	21.7	16.3	$32,226	$27,092

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

Operating	2010	2009		2010	2009
	(thousands of barrels daily)			(thousands of barrels daily)	
Net liquids production			Refinery throughput		
United States	408	384	United States	1,753	1,767
Non-U.S.	2,014	2,003	Non-U.S.	3,500	3,583
Total	2,422	2,387	Total	5,253	5,350
	(millions of cubic feet daily)			(thousands of barrels daily)	
Natural gas production available for sale			Petroleum product sales		
United States	2,596	1,275	United States	2,511	2,523
Non-U.S.	9,552	7,998	Non-U.S.	3,903	3,905
Total	12,148	9,273	Total	6,414	6,428
	(thousands of oil-equivalent barrels daily)			(thousands of metric tons)	
Oil-equivalent production (1)	4,447	3,932	Chemical prime product sales		
			United States	9,815	9,649
			Non-U.S.	16,076	15,176
			Total	25,891	24,825

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

FINANCIAL SUMMARY

	2010 (1)	2009	2008	2007	2006
		(millions of dollars, except per share amounts)			
Sales and other operating revenue (2)	$370,125	$301,500	$459,579	$390,328	$365,467
Earnings					
Upstream	$ 24,097	$ 17,107	$ 35,402	$ 26,497	$ 26,230
Downstream	3,567	1,781	8,151	9,573	8,454
Chemical	4,913	2,309	2,957	4,563	4,382
Corporate and financing	(2,117)	(1,917)	(1,290)	(23)	434
Net income attributable to ExxonMobil	$ 30,460	$ 19,280	$ 45,220	$ 40,610	$ 39,500
Earnings per common share	$ 6.24	$ 3.99	$ 8.70	$ 7.31	$ 6.64
Earnings per common share – assuming dilution	$ 6.22	$ 3.98	$ 8.66	$ 7.26	$ 6.60
Cash dividends per common share	$ 1.74	$ 1.66	$ 1.55	$ 1.37	$ 1.28
Earnings to average ExxonMobil share of equity (percent)	23.7	17.3	38.5	34.5	35.1
Working capital	$ (3,649)	$ 3,174	$ 23,166	$ 27,651	$ 26,960
Ratio of current assets to current liabilities (times)	0.94	1.06	1.47	1.47	1.55
Additions to property, plant and equipment	$ 74,156	$ 22,491	$ 19,318	$ 15,387	$ 15,462
Property, plant and equipment, less allowances	$199,548	$139,116	$121,346	$120,869	$113,687
Total assets	$302,510	$233,323	$228,052	$242,082	$219,015
Exploration expenses, including dry holes	$ 2,144	$ 2,021	$ 1,451	$ 1,469	$ 1,181
Research and development costs	$ 1,012	$ 1,050	$ 847	$ 814	$ 733
Long-term debt	$ 12,227	$ 7,129	$ 7,025	$ 7,183	$ 6,645
Total debt	$ 15,014	$ 9,605	$ 9,425	$ 9,566	$ 8,347
Fixed-charge coverage ratio (times)	42.2	25.8	54.6	51.6	47.8
Debt to capital (percent)	9.0	7.7	7.4	7.1	6.6
Net debt to capital (percent) (3)	4.5	(1.0)	(23.0)	(24.0)	(20.4)
ExxonMobil share of equity at year end	$146,839	$110,569	$112,965	$121,762	$113,844
ExxonMobil share of equity per common share	$ 29.48	$ 23.39	$ 22.70	$ 22.62	$ 19.87
Weighted average number of common shares outstanding (millions)	4,885	4,832	5,194	5,557	5,948
Number of regular employees at year end (thousands) (4)	83.6	80.7	79.9	80.8	82.1
CORS employees not included above (thousands) (5)	20.1	22.0	24.8	26.3	24.3

(1) *See Note 19: Acquisition of XTO Energy Inc.*

(2) *Sales and other operating revenue includes sales-based taxes of $28,547 million for 2010, $25,936 million for 2009, $34,508 million for 2008, $31,728 million for 2007 and $30,381 million for 2006.*

(3) *Debt net of cash, excluding restricted cash.*

(4) *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.*

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

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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 reflects 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 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	2010	2009	2008
		(millions of dollars)	
Net cash provided by operating activities	$48,413	$28,438	$59,725
Sales of subsidiaries, investments and property, plant and equipment	3,261	1,545	5,985
Cash flow from operations and asset sales	$51,674	$29,983	$65,710

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 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	2010	2009	2008
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	$302,510	$233,323	$228,052
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(59,846)	(49,585)	(46,700)
Total long-term liabilities excluding long-term debt	(74,971)	(58,741)	(54,404)
Noncontrolling interests share of assets and liabilities	(6,532)	(5,642)	(6,044)
Add ExxonMobil share of debt-financed equity company net assets	4,875	5,043	4,798
Total capital employed	$166,036	$124,398	$125,702
Total corporate sources: debt and equity perspective			
Notes and loans payable	$ 2,787	$ 2,476	$ 2,400
Long-term debt	12,227	7,129	7,025
ExxonMobil share of equity	146,839	110,569	112,965
Less noncontrolling interests share of total debt	(692)	(819)	(1,486)
Add ExxonMobil share of equity company debt	4,875	5,043	4,798
Total capital employed	$166,036	$124,398	$125,702

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 attributable to ExxonMobil 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 are more cash flow-based, are used to make investment decisions.

Return on average capital employed	2010	2009	2008
		(millions of dollars)	
Net income attributable to ExxonMobil	$ 30,460	$ 19,280	$ 45,220
Financing costs (after tax)			
Gross third-party debt	(803)	(303)	(343)
ExxonMobil share of equity companies	(333)	(285)	(325)
All other financing costs – net	35	(483)	1,485
Total financing costs	(1,101)	(1,071)	817
Earnings excluding financing costs	$ 31,561	$ 20,351	$ 44,403
Average capital employed	$145,217	$125,050	$129,683
Return on average capital employed – corporate total	21.7%	16.3%	34.2%

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QUARTERLY INFORMATION

	2010					2009				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
	(thousands of barrels daily)									
Volumes										
Production of crude oil and natural gas liquids, synthetic oil and bitumen	2,414	2,325	2,421	2,526	2,422	2,476	2,346	2,335	2,393	2,387
Refinery throughput	5,156	5,192	5,364	5,298	5,253	5,381	5,290	5,352	5,379	5,350
Petroleum product sales	6,195	6,304	6,595	6,555	6,414	6,434	6,487	6,301	6,489	6,428
	(millions of cubic feet daily)									
Natural gas production available for sale	11,689	10,025	12,192	14,652	12,148	10,187	8,041	8,155	10,717	9,273
	(thousands of oil-equivalent barrels daily)									
Oil-equivalent production (1)	4,362	3,996	4,453	4,968	4,447	4,174	3,686	3,694	4,179	3,932
	(thousands of metric tons)									
Chemical prime product sales	6,488	6,496	6,558	6,349	25,891	5,527	6,267	6,356	6,675	24,825
	(millions of dollars)									
Summarized financial data										
Sales and other operating revenue (2)	$87,037	89,693	92,353	101,042	370,125	$62,128	72,167	80,090	87,115	301,500
Gross profit (3)	$28,537	29,482	30,652	32,943	121,614	$23,562	24,231	27,377	28,580	103,750
Net income attributable to ExxonMobil	$ 6,300	7,560	7,350	9,250	30,460	$ 4,550	3,950	4,730	6,050	19,280
	(dollars per share)									
Per share data										
Earnings per common share (4)	$ 1.33	1.61	1.44	1.86	6.24	$ 0.92	0.82	0.98	1.27	3.99
Earnings per common share – assuming dilution (4)	$ 1.33	1.60	1.44	1.85	6.22	$ 0.92	0.81	0.98	1.27	3.98
Dividends per common share	$ 0.42	0.44	0.44	0.44	1.74	$ 0.40	0.42	0.42	0.42	1.66
Common stock prices										
High	$ 70.60	70.00	62.99	73.69	73.69	$ 82.73	74.83	72.79	76.54	82.73
Low	$ 63.56	56.92	55.94	61.80	55.94	$ 61.86	64.50	64.46	66.11	61.86

(1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.
(2) Includes amounts for sales-based taxes.
(3) Gross profit equals sales and other operating revenue less estimated costs associated with products sold.
(4) Computed using the average number of shares outstanding during each period. The sum of the four quarters may not add to the full year.

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 507,028 registered shareholders of ExxonMobil common stock at December 31, 2010. At January 31, 2011, the registered shareholders of ExxonMobil common stock numbered 505,330.

On January 26, 2011, the Corporation declared a $0.44 dividend per common share, payable March 10, 2011.

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

FUNCTIONAL EARNINGS

	2010	2009	2008
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	$ 4,272	$ 2,893	$ 6,243
Non-U.S.	19,825	14,214	29,159
Downstream			
United States	770	(153)	1,649
Non-U.S.	2,797	1,934	6,502
Chemical			
United States	2,422	769	724
Non-U.S.	2,491	1,540	2,233
Corporate and financing	(2,117)	(1,917)	(1,290)
Net income attributable to ExxonMobil	$30,460	$19,280	$45,220
Earnings per common share	$ 6.24	$ 3.99	$ 8.70
Earnings per common share – assuming dilution	$ 6.22	$ 3.98	$ 8.66
Special items included in earnings			
Non-U.S. Upstream			
Gain on German natural gas transportation business sale	$ —	$ —	$ 1,620
Corporate and financing			
Valdez litigation	$ —	$ (140)	$ (460)

References in this discussion to total corporate earnings mean net income attributable to ExxonMobil (U.S. GAAP) from the consolidated income statement. Unless otherwise indicated, references to earnings, special items, Upstream, Downstream, Chemical and Corporate and Financing segment earnings, and earnings per share are ExxonMobil's share after excluding amounts attributable to noncontrolling interests.

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 energy source mix; capacity increases; production growth and mix; rates of field decline; financing sources; the resolution of contingencies and uncertain tax positions; environmental and capital expenditures; could differ materially depending on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products; the outcome of commercial negotiations; political or regulatory events, and other factors discussed herein and in Item 1A of ExxonMobil's 2010 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, manufacturing 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.

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 are volatile on a short-term basis and depend on supply and demand, ExxonMobil's investment decisions are based on our long-term business outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. 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 are utilized 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.

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

By 2030, the world's population is projected to grow to approximately 8 billion people, or about 1.5 billion more than in 2005. Coincident with this population increase, the Corporation expects worldwide economic growth to average 2.8 percent per year. This combination of population and economic growth is expected to lead to an increase in primary energy demand of about 35 percent by 2030 versus 2005, even with substantial efficiency gains around the world. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organization for Economic Cooperation and Development).

As economic progress drives demand higher, increasing penetration of energy-efficient and lower-emission fuels, technologies and practices are expected to contribute to significantly lower levels of energy consumption and emissions per unit of economic output over time. Efficiency gains will result from anticipated improvements in the transportation and power generation sectors, driven by the introduction of new technologies, as well as many other improvements that span the residential, commercial and industrial sectors.

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by nearly 40 percent from 2005 to 2030. The global growth in transportation demand is likely to account for approximately 80 percent of the growth in oil demand over this period. Nearly all the world's transportation fleets will continue to run on liquid fuels because they provide a large quantity of energy in small volumes, making them easy to transport and widely available.

Demand for electricity around the world will grow significantly through 2030. Consistent with this projection, power generation will remain the largest and fastest-growing major segment of global energy demand. Meeting the expected growth in power demand will require a diverse set of energy sources. Natural gas demand will grow most significantly and gain the most market share, although coal demand will also grow and retain the largest share through 2030 despite also losing share to nuclear and wind.

Liquid fuels provide the largest share of energy supply today due to their availability, affordability and ease of transport. By 2030, global demand for liquids is expected to grow to approximately 103 million barrels of oil-equivalent per day, an increase of more than 20 percent from 2005. Global demand for liquid fuels will be met by a wide variety of sources. Conventional non-OPEC crude and condensate production is expected to remain relatively flat through 2030. However, growth is expected from a number of supply sources, including biofuels, oil sands and natural gas liquids, as well as crude oil from OPEC countries. While the world's resource base is sufficient to meet projected demand, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Increases in natural gas demand in North America, Europe and Asia Pacific will require new sources of supply. Helping meet these needs will be additional local supplies of unconventional natural gas – the result of recent improvements in technologies used to tap these hard-to-produce resources – as well as imports. The growing need for natural gas imports will have a dramatic impact on the worldwide liquefied natural gas (LNG) market, which is expected to approximately triple in volume from 2005 to 2030.

The world's energy mix is highly diverse and will remain so through 2030. Oil is expected to remain the largest source of energy supply at close to 32 percent. From 2005 to 2030, natural gas is expected to grow the fastest of the major energy types and overtake coal as the second-largest energy source. Nuclear power is projected to grow significantly, on par with coal in terms of absolute growth and surpassing biomass as the fourth-largest source of energy. Hydro and geothermal will also grow, though remain limited by the availability of natural sites. Wind, solar and biofuels are expected to grow at close to 10 percent per year on average, the highest growth rate of all fuels, and are projected to reach approximately 2.5 percent of world energy by 2030.

The Corporation anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from reserve increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these resources will be significant. According to the International Energy Agency, the investment required to meet total oil and gas energy needs worldwide over the period 2010-2035 will be approximately $15 trillion (measured in 2009 dollars) or close to $580 billion per year on average.

International accords and underlying regional and national regulations for greenhouse gas reduction are evolving with uncertain timing and outcome, making it difficult to predict their business impact. ExxonMobil includes estimates of potential costs related to possible public policies covering energy-related greenhouse gas emissions in its long-term Energy Outlook, which is used for assessing the business environment and in its investment evaluations.

The information provided in the Long-Term Business Outlook includes ExxonMobil's internal estimates and forecasts based upon internal data and analyses as well as publicly available information from external sources including the International Energy Agency.

Upstream

ExxonMobil continues to maintain a large portfolio of exploration and development opportunities, which enables the Corporation to be selective, maximizing shareholder value and mitigating political and technical risks. ExxonMobil's fundamental Upstream business strategies guide our global exploration, development, production, and gas and power marketing activities. These strategies include identifying and selectively pursuing the highest quality exploration opportunities, investing in projects that deliver superior returns, maximizing profitability of existing oil and gas production, and capitalizing on growing natural gas and power markets. These strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technologies, development of our employees and investment in the communities in which we operate.

As future development projects and drilling activities bring new production online, the Corporation expects a shift in the geographic mix of its production volumes between now and 2015. Oil and natural gas output from North America is expected to increase over the next five years based on current capital activity plans. Currently, this growth area accounts for 27 percent of the Corporation's production. By 2015, it is expected to generate about 35 percent of total volumes. The remainder of the Corporation's production is expected to be sourced from Asia, Europe, Africa and Australia, with contributions from both established operations and new projects.

In addition to an evolving geographic mix, there will also be continued change in the type of opportunities from which volumes are produced. Production from diverse resource types utilizing specialized technologies such as arctic technology, deepwater drilling and production systems, heavy oil recovery processes, unconventional gas production and LNG is expected to grow from about 40 percent to around 55 percent of the Corporation's output between now and 2015. We do not anticipate that the expected change in the geographic mix of production volumes, and in the types of opportunities from which volumes will be produced, will have a material impact on the nature and the extent of the risks disclosed in Item 1A of ExxonMobil's 2010 Form 10-K, or result in a material change in our level of unit operating expenses. The Corporation's overall volume capacity outlook, based on projects coming onstream as anticipated, is for production capacity to grow over the period 2011-2015. However, actual volumes will vary from year to year due to the timing of individual project start-ups and other capital activities, operational outages, reservoir performance, performance of enhanced oil recovery projects, regulatory changes, asset sales, weather events, price effects under production sharing contracts and other factors described in Item 1A of ExxonMobil's 2010 Form 10-K. Enhanced oil recovery projects extract hydrocarbons from reservoirs in excess of that which may be produced through primary recovery, i.e., through pressure depletion or natural aquifer support. They include the injection of water, gases or chemicals into a reservoir to produce hydrocarbons otherwise unobtainable.

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

Downstream

ExxonMobil's Downstream is a large, diversified business with refining and marketing complexes around the world. The Corporation has a strong presence in mature markets in North America and Europe, as well as the growing Asia Pacific region. ExxonMobil's fundamental Downstream business strategies position the company to deliver long-term growth in shareholder value that is superior to competition across a range of market conditions. These strategies include maintaining best-in-class operations in all aspects of the business, maximizing value from leading-edge technologies, capitalizing on integration across ExxonMobil businesses, selectively investing for resilient, advantaged returns, leading the industry in efficiency and effectiveness, and providing quality, valued products and services to customers.

ExxonMobil has an ownership interest in 36 refineries, located in 21 countries, with distillation capacity of 6.3 million barrels per day and lubricant basestock manufacturing capacity of about 131 thousand barrels per day. ExxonMobil's fuels and lubes marketing business portfolios include operations around the world, with multiple channels to market serving a globally diverse customer base.

The downstream industry environment remains challenging. Although demand for refined products has improved from the lower levels in 2009 due to the recent global economic recession, we expect the challenging business environment to continue, reflecting the increase in global refining capacity and regulatory-related policies. Over the prior 20-year period, inflation-adjusted refining margins have been flat.

Refining margins are largely driven by differences in commodity prices and 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, diesel 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 Intercontinental Exchange). Prices for these commodities are determined by the global marketplace and are influenced by many factors, including global and regional supply/demand balances, inventory levels, refinery operations, import/export balances, currency fluctuations, seasonal demand, weather and political climate.

ExxonMobil's long-term outlook is that refining margins will remain weak as competition in the refining industry remains intense and, in the near term, new capacity additions outpace the growth in global demand. Additionally, as described in more detail in Item 1A of ExxonMobil's 2010 Form 10-K, proposed carbon policy and other climate-related regulations in many countries, as well as the continued growth in biofuels mandates, could have negative impacts on the refining business.

In the retail fuels marketing business, competition continues to cause inflation-adjusted margins to decline. In 2010, ExxonMobil progressed the transition of the direct served (i.e., dealer, company-operated) retail network in the U.S. to a branded distributor model. This transition was announced in 2008 and will be a multiyear process.

ExxonMobil takes a disciplined approach to managing the Downstream capital employed. The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. These investments capitalize on the Corporation's world-class scale and integration, industry-leading efficiency, leading-edge technology and respected brands, enabling ExxonMobil to take advantage of attractive emerging-growth opportunities around the globe. In 2010, ExxonMobil invested over $1 billion in three refineries to increase the supply of cleaner-burning diesel by about 140 thousand barrels per day. The company completed construction of new units and modification of existing facilities at its Baton Rouge, Louisiana; Baytown, Texas; and Antwerp, Belgium, refineries. In addition, construction has commenced at the Sriracha, Thailand, refinery to produce lower sulfur diesel and gasoline to meet upcoming product specifications in Thailand. Completion is expected in the fourth quarter of 2011. At the Jurong/PAC refinery in Singapore, plans are under way to build a new diesel hydrotreater, which will add a capacity of more than 2 million gallons per day to meet increasing demand in the Asia Pacific region.

Chemical

Worldwide petrochemical demand recovered from the economic downturn in 2008 and the first half of 2009. Tighter industry supply/ demand balances throughout the year supported improved industry margins, particularly in the U.S. Asia Pacific commodity margins were lower, reflecting the start-up of significant new industry capacity in the region.

ExxonMobil benefited from continued operational excellence and a balanced portfolio of products. In addition to being a worldwide supplier of commodity petrochemical products, ExxonMobil Chemical also has a number of less-cyclical business lines, which delivered strong results in 2010. Chemical's competitive advantages are due to its business mix, broad geographic coverage, investment and cost discipline, integration with refineries or upstream gas processing facilities, superior feedstock management, leading proprietary technology and product application expertise.

REVIEW OF 2010 AND 2009 RESULTS

	2010	2009	2008
		(millions of dollars)	
Earnings (U.S. GAAP)	$30,460	$19,280	$45,220

2010

Earnings in 2010 of $30,460 million increased $11,180 million from 2009. Earnings for 2010 did not include any special items.

2009

Earnings in 2009 of $19,280 million decreased $25,940 million from 2008. Earnings for 2009 included an after-tax special charge of $140 million for interest related to the Valdez punitive damages award.

Upstream

	2010	2009	2008
		(millions of dollars)	
Upstream			
United States	$ 4,272	$ 2,893	$ 6,243
Non-U.S.	19,825	14,214	29,159
Total	$24,097	$17,107	$35,402

2010

Upstream earnings were $24,097 million, up $6,990 million from 2009. Higher realizations increased earnings approximately $6.5 billion. Higher volumes increased earnings by $1.2 billion, while all other items, including higher operating costs, decreased earnings by $690 million. On an oil-equivalent basis, production was up 13 percent compared to 2009. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was up 14 percent. Liquids production of 2,422 kbd (thousands of barrels per day) increased 35 kbd compared with 2009. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production increased 2 percent from 2009, as project ramp-ups in Qatar were offset by net field decline. Natural gas production of 12,148 mcfd (millions of cubic feet per day) increased 2,875 mcfd from 2009, driven by higher volumes from Qatar projects and additional U.S. unconventional gas volumes. Earnings from U.S. Upstream operations for 2010 were $4,272 million, an increase of $1,379 million from 2009. Non-U.S. Upstream earnings were $19,825 million, up $5,611 million from 2009.

2009

Upstream earnings for 2009 were $17,107 million, down $18,295 million from 2008, including the absence of an after-tax special gain in 2008 of $1,620 million from the sale of a natural gas transportation business in Germany. Lower crude oil and natural gas realizations reduced earnings $15.2 billion. Volume and mix effects increased earnings $700 million. Higher operating expenses and increased exploration activities decreased earnings $1.4 billion. Lower gains on asset divestments reduced earnings approximately $900 million. Oil-equivalent production increased slightly versus 2008, including impacts from entitlement effects, quotas and divestments. Excluding these items, oil-equivalent production was up about 2 percent. Liquids production of 2,387 kbd decreased 18 kbd. Production increases from new projects in the U.S., Qatar and Africa along with higher volumes in Kazakhstan were offset by field decline. Natural gas production of 9,273 mcfd increased 178 mcfd from 2008. Higher volumes from projects in Qatar were partially offset by field decline. Earnings from U.S. Upstream operations for 2009 were $2,893 million, a decrease of $3,350 million. Earnings outside the U.S. for 2009 of $14,214 million declined $14,945 million.

Downstream

	2010	2009	2008
		(millions of dollars)	
Downstream			
United States	$ 770	$ (153)	$1,649
Non-U.S.	2,797	1,934	6,502
Total	$3,567	$1,781	$8,151

2010

Downstream earnings of $3,567 million were $1,786 million higher than 2009. Higher industry refining margins increased earnings by $1.2 billion. Positive volume and mix effects increased earnings by $420 million, while all other items, including lower operating expenses, increased earnings by $210 million. Petroleum product sales of 6,414 kbd decreased 14 kbd. U.S. Downstream earnings were $770 million, up $923 million from 2009. Non-U.S. Downstream earnings were $2,797 million, $863 million higher than 2009.

2009

Downstream earnings were $1,781 million, down $6.4 billion from 2008. Weaker margins reduced earnings $5.1 billion. Lower divestment activity reduced earnings about $1.0 billion. Volumes decreased earnings approximately $300 million. Petroleum product sales of 6,428 kbd decreased 333 kbd, mainly reflecting asset divestments and lower demand. Refinery throughput was 5,350 kbd, down 66 kbd from 2008. Earnings from the U.S. Downstream were $1,802 million lower than in 2008. Non-U.S. Downstream earnings were $1,934 million, down $4,568 million from 2008.

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

Chemical

	2010	2009	2008
		(millions of dollars)	
Chemical			
United States	$2,422	$ 769	$ 724
Non-U.S.	2,491	1,540	2,233
Total	$4,913	$2,309	$2,957

2010

Chemical earnings were a record $4,913 million, up $2,604 million from 2009. Improved margins increased earnings by $2.0 billion while higher volumes increased earnings $380 million. Prime product sales of 25,891 kt were up 1,066 kt from 2009. Prime product sales are total chemical product sales, including ExxonMobil's share of equity-company volumes and finished product transfers to the Downstream business. U.S. Chemical earnings of $2,422 million increased $1,653 million. Non-U.S. Chemical earnings of $2,491 million increased $951 million.

2009

Earnings declined $648 million versus 2008 to a total of $2,309 million. Weaker margins reduced earnings by $340 million, mostly in commodities. Lower volumes decreased earnings $190 million. All other items, including unfavorable foreign exchange impacts, reduced earnings $115 million. Prime product sales of 24,825 kt decreased 157 kt from 2008. U.S. Chemical earnings of $769 million increased $45 million. Non-U.S. Chemical earnings were $1,540 million, down $693 million.

Corporate and Financing

	2010	2009	2008
		(millions of dollars)	
Corporate and financing	$(2,117)	$(1,917)	$(1,290)

2010

Corporate and financing expenses were $2,117 million, up $200 million from 2009 mainly due to a tax charge related to the U.S. health care legislation during the first quarter of 2010 and financing activities, partially offset by the absence of a 2009 charge for interest related to the Valdez punitive damages award.

2009

Corporate and financing expenses of $1,917 million in 2009 increased $627 million, primarily due to lower interest income.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2010	2009	2008
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	$ 48,413	$ 28,438	$ 59,725
Investing activities	(24,204)	(22,419)	(15,499)
Financing activities	(26,924)	(27,283)	(44,027)
Effect of exchange rate changes	(153)	520	(2,743)
Increase/(decrease) in cash and cash equivalents	$ (2,868)	$(20,744)	$ (2,544)
		(Dec. 31)	
Cash and cash equivalents	$ 7,825	$ 10,693	$ 31,437
Cash and cash equivalents – restricted	628	—	—
Total cash and cash equivalents	$ 8,453	$ 10,693	$ 31,437

Total cash and cash equivalents were $8.5 billion at the end of 2010, $2.2 billion lower than the prior year. Higher earnings and reduced share purchases were offset by a higher level of capital spending and increased level of debt repurchases. Included in total cash and cash equivalents at year-end 2010 was $0.6 billion of restricted cash.

Cash and cash equivalents were $10.7 billion at the end of 2009, $20.7 billion lower than the prior year, reflecting lower earnings and a higher level of capital spending partially offset by a lower level of purchases of ExxonMobil shares. Cash flows from operating, investing and financing activities are discussed below. For additional details, see the Consolidated Statement of Cash Flows.

Although the Corporation has access to significant capacity of long-term and short-term liquidity, 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 to ensure it is secure and readily available to meet the Corporation's cash requirements and to optimize returns on the cash balances.

To support cash flows in future periods 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. 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 the Corporation's existing oil and gas fields and without new projects, ExxonMobil's production is expected to decline at an average of approximately 3 percent per year over the next few years. 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, work activity, and age of the field. Furthermore, the Corporation’s net interest in production 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 in quality opportunities and project execution. Over the last decade, this has resulted in net annual additions to proved reserves that have exceeded the amount produced. 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, weather events, and regulatory changes. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please refer to Item 1A. Risk Factors for a more complete discussion of risks.

The Corporation's financial strength enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2010 were $32.2 billion, reflecting the Corporation's continued active investment program. The Corporation expects annual expenditures to range from $33 billion to $37 billion for the next several years. Actual spending could vary depending on the 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.

Cash Flow from Operating Activities

2010

Cash provided by operating activities totaled $48.4 billion in 2010, $20.0 billion higher than 2009. The major source of funds was net income including noncontrolling interests of $31.4 billion, adjusted for the noncash provision of $14.8 billion for depreciation and depletion, both of which increased. The net effects of changes in prices and the timing of collection of accounts receivable and of payments of accounts and other payables and of income taxes payable increased cash provided by operating activities in 2010 compared to a decrease in 2009, and resulted in net working capital of $(3.6) billion as total current liabilities of $62.6 billion exceeded total current assets of $59.0 billion at year-end 2010.

2009

Cash provided by operating activities totaled $28.4 billion in 2009, $31.3 billion lower than 2008. The major source of funds was net income including noncontrolling interests of $19.7 billion, adjusted for the noncash provision of $11.9 billion for depreciation and depletion, both of which declined. Pension fund contributions in 2009 of $4.5 billion increased from $1.0 billion in 2008. The net effects of changes in prices and the timing of collection of accounts receivable and of payments of accounts and other payables and of income taxes payable reduced cash provided by operating activities in 2009 compared to an increase in 2008.

Cash Flow from Investing Activities

2010

Cash used in investment activities netted to $24.2 billion in 2010, $1.8 billion higher than in 2009. Spending for property, plant and equipment of $26.9 billion increased $4.4 billion from 2009. Proceeds from the sale of subsidiaries, investments and property, plant and equipment of $3.3 billion in 2010 compared to $1.5 billion in 2009, the increase reflecting the sale of some U.S. service stations and Upstream Gulf of Mexico and other producing properties.

2009

Cash used in investing activities netted to $22.4 billion in 2009, $6.9 billion higher than in 2008. Spending for property, plant and equipment of $22.5 billion in 2009 increased $3.2 billion from 2008. Proceeds from the sales of subsidiaries, investments and property, plant and equipment of $1.5 billion in 2009 compared to $6.0 billion in 2008, the decrease reflecting the absence of the sale of the natural gas transportation business in Germany and lower sales of Downstream assets and investments.

Cash Flow from Financing Activities

2010

Cash used in financing activities was $26.9 billion in 2010, $0.4 billion lower than 2009. Dividend payments on common shares increased to $1.74 per share from $1.66 per share and totaled $8.5 billion, a pay-out of 28 percent. Total debt increased to $15.0 billion at year end, an increase of $5.4 billion from 2009, primarily as a result of debt assumed with the XTO merger.

ExxonMobil share of equity increased $36.3 billion to $146.8 billion. The addition to equity for earnings of $30.5 billion and the issuance of stock for the XTO merger of $24.7 billion was partially offset by reductions to equity for distributions to ExxonMobil shareholders of $8.5 billion of dividends and $11.2 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding.

During 2010, Exxon Mobil Corporation issued 416 million shares for the XTO merger. Exxon Mobil Corporation purchased 199 million shares of its common stock for the treasury at a gross cost of $13.1 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding increased by 5.3 percent from 4,727 million at the end of 2009 to 4,979 million at the end of 2010. Purchases were made in both the open market and negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2009

Cash used in financing activities was $27.3 billion in 2009, $16.7 billion lower than 2008, reflecting a lower level of purchases of ExxonMobil shares. Dividend payments on common shares increased to $1.66 per share from $1.55 per share and totaled $8.0 billion, a pay-out of 42 percent. Total consolidated short-term and long-term debt increased

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

$0.2 billion to $9.6 billion at year-end 2009.

ExxonMobil share of equity decreased $2.4 billion in 2009, to $110.6 billion. The addition to equity for earnings of $19.3 billion was more than offset by reductions for distributions to ExxonMobil shareholders of $8.0 billion of dividends and $18.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding. Equity, and net assets and liabilities, increased $3.3 billion, representing the foreign exchange translation effects of generally stronger foreign currencies at the end of 2009 on ExxonMobil's operations outside the United States. The change in the funded status of the postretirement benefits reserves in 2009 increased equity by $1.2 billion.

During 2009, Exxon Mobil Corporation purchased 277 million shares of its common stock for the treasury at a gross cost of $19.7 billion. These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 5.0 percent from 4,976 million at the end of 2008 to 4,727 million at the end of 2009. Purchases were made in both the open market and through negotiated transactions.

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2010. It combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

	Payments Due by Period				
Commitments	Note Reference Number	2011	2012-2015	2016 and Beyond	Total
			(millions of dollars)		
Long-term debt (1)	13	$ —	$ 5,464	$ 6,763	$12,227
- Due in one year (2)	5	345	—	—	345
Asset retirement obligations (3)	8	775	2,196	6,643	9,614
Pension and other postretirement obligations (4)	16	2,541	4,130	13,231	19,902
Operating leases (5)	10	2,095	3,943	1,738	7,776
Unconditional purchase obligations (6)	15	287	748	487	1,522
Take-or-pay obligations (7)		1,704	6,275	8,832	16,811
Firm capital commitments (8)		14,851	12,329	948	28,128

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. The table also excludes unrecognized tax benefits totaling $4.1 billion as of December 31, 2010, because the Corporation is unable to make reasonably reliable estimates of the timing of cash settlements with the respective taxing authorities. Further details on the unrecognized tax benefits can be found in note 18, Income, Sales-Based and Other Taxes.

Notes:

(1) Includes capitalized lease obligations of $304 million.
(2) The amount due in one year is included in notes and loans payable of $2,787 million.
(3) The fair value of asset retirement obligations, primarily upstream asset removal costs at the completion of field life.
(4) The amount by which the benefit obligations exceeded the fair value of fund assets for certain U.S. and non-U.S. pension and other postretirement plans at year end. The payments by period include expected contributions to funded pension plans in 2011 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 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. The undiscounted obligations of $1,522 million mainly pertain to pipeline throughput agreements and include $996 million of obligations to equity companies.
(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undiscounted obligations of $16,811 million mainly pertain to manufacturing supply, pipeline and terminaling agreements and include $507 million of obligations to equity companies.
(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $28.1 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which $17.2 billion was associated with projects in Australia, Africa, Malaysia and Canada. The Corporation expects to fund the majority of these projects through internal cash flow.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2010, for $8,771 million, primarily relating to guarantees for notes, loans and performance under contracts (note 15). Included in this amount were guarantees by consolidated affiliates of $5,290 million, representing ExxonMobil's share of obligations of certain equity companies. The below-mentioned guarantees are not reasonably likely to have a material 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, 2010		
	Equity Company Obligations	Other Third-Party Obligations	Total
		(millions of dollars)	
Guarantees	$ 5,290	$ 3,481	$8,771

Financial Strength

On December 31, 2010, unused credit lines for short-term financing totaled approximately $5.6 billion (note 5).

The table below shows the Corporation's fixed-charge coverage and consolidated debt-to-capital ratios. The data demonstrate the Corporation's creditworthiness.

	2010	2009	2008
Fixed-charge coverage ratio (times)	42.2	25.8	54.6
Debt to capital (percent)	9.0	7.7	7.4
Net debt to capital (percent)	4.5	(1.0)	(23.0)

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.

Litigation and Other Contingencies

Litigation. As discussed in note 15, a variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. 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, financial condition, or financial statements taken as a whole. There are no events or uncertainties beyond those already included in reported financial information that would indicate a material change in future operating results or financial condition.

Other Contingencies. In accordance with a nationalization decree issued by Venezuela's president in February 2007, by May 1, 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. This Project had been operated and owned by ExxonMobil affiliates holding a 41.67 percent ownership interest in the Project. The decree also required conversion of the Cerro Negro Project into a "mixed enterprise" and an increase in PdVSA's or one of its affiliate's ownership interest in the Project, with the stipulation that if ExxonMobil refused to accept the terms for the formation of the mixed enterprise within a specified period of time, the government would "directly assume the activities" carried out by the joint venture. ExxonMobil refused to accede to the terms proffered by the government, and on June 27, 2007, the government expropriated ExxonMobil's 41.67 percent interest in the Cerro Negro Project.

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID) invoking ICSID jurisdiction under Venezuela's Investment Law and the Netherlands-Venezuela Bilateral Investment Treaty. The ICSID Tribunal issued a decision on June 10, 2010, finding that it had jurisdiction to proceed on the basis of the Netherlands-Venezuela Bilateral Investment Treaty. The ICSID arbitration proceeding is continuing and a hearing on the merits is currently scheduled for the first quarter of 2012. An affiliate of ExxonMobil has also filed an arbitration under the rules of the International Chamber of Commerce (ICC) against PdVSA and a PdVSA affiliate for breach of their contractual obligations under certain Cerro Negro Project agreements. A hearing on the merits of the ICC arbitration concluded in September 2010 and the parties have filed post-hearing briefs. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition. ExxonMobil's remaining net book investment in Cerro Negro producing assets is about $750 million.

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

CAPITAL AND EXPLORATION EXPENDITURES

	2010		2009	
	U.S.	Non-U.S.	U.S.	Non-U.S.
	(millions of dollars)			
Upstream (1)	$6,349	$20,970	$3,585	$17,119
Downstream	982	1,523	1,511	1,685
Chemical	279	1,936	319	2,829
Other	187	—	44	—
Total	$7,797	$24,429	$5,459	$21,633

(1) Exploration expenses included.

Capital and exploration expenditures in 2010 were $32.2 billion, reflecting the Corporation's continued active investment program. The Corporation expects annual expenditures to range from $33 billion to $37 billion for the next several years. Actual spending could vary depending on the progress of individual projects.

Upstream spending of $27.3 billion in 2010 was up 32 percent from 2009, reflecting unconventional gas activities in the U.S. and continued progress on world-class projects in Canada, Australia and Papua New Guinea. The majority of expenditures are on 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 was 69 percent of total proved reserves at year-end 2010, and has been over 60 percent for the last five years, indicating that proved reserves are consistently moved from undeveloped to developed status. Capital investments in the Downstream totaled $2.5 billion in 2010, a decrease of $0.7 billion from 2009, due to completion of environmental-related refining projects, primarily in the U.S. The Chemical capital expenditures of $2.2 billion were $0.9 billion lower in 2010 as investments in Asia to meet demand growth progressed toward completion.

TAXES

	2010	2009	2008
	(millions of dollars)		
Income taxes	$21,561	$15,119	$ 36,530
Effective income tax rate	*45%*	*47%*	*46%*
Sales-based taxes	28,547	25,936	34,508
All other taxes and duties	39,127	37,571	45,223
Total	$89,235	$78,626	$116,261

2010

Income, sales-based and all other taxes and duties totaled $89.2 billion in 2010, an increase of $10.6 billion or 13 percent from 2009. Income tax expense, both current and deferred, was $21.6 billion, $6.4 billion higher than 2009, reflecting higher pre-tax income in 2010. A lower share of pre-tax income from the Upstream segment in 2010 decreased the effective tax rate to 45 percent compared to 47 percent in 2009. Sales-based and all other taxes and duties of $67.7 billion in 2010 increased $4.2 billion, reflecting higher prices.

2009

Income, sales-based and all other taxes and duties totaled $78.6 billion in 2009, a decrease of $37.6 billion or 32 percent from 2008. Income tax expense, both current and deferred, was $15.1 billion, $21.4 billion lower than 2008, reflecting lower pre-tax income in 2009. A higher share of total income from the Upstream segment in 2009 increased the effective income tax rate to 47 percent compared to 46 percent in 2008. Sales-based and all other taxes and duties of $63.5 billion in 2009 decreased $16.2 billion from 2008, reflecting lower prices and foreign exchange effects.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2010	2009
	(millions of dollars)	
Capital expenditures	$1,947	$2,481
Other expenditures	2,593	2,610
Total	$4,540	$5,091

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels as well as projects to monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions and expenditures for asset retirement obligations. ExxonMobil's 2010 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about $4.5 billion. The total cost for such activities is expected to remain in this range in 2011 and 2012 (with capital expenditures approximately 40 percent of the total).

Environmental Liabilities

The Corporation accrues 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 could mitigate 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. Consolidated company provisions made in 2010 for environmental liabilities were $448 million ($504 million in 2009) and the balance sheet reflects accumulated liabilities of $948 million as of December 31, 2010, and $943 million as of December 31, 2009.

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 ($1,094 million for 2010). Over time, the liabilities are accreted for the increase in their present value, with this effect included in expenses ($563 million in 2010). Consolidated company expenditures for asset retirement obligations in 2010 were $638 million and the obligations recorded on the balance sheet at December 31, 2010, totaled $9,614 million.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations(1)	2010	2009	2008
Crude oil and NGL ($/barrel)	$74.04	$57.86	$90.96
Natural gas ($/kcf)	4.31	4.00	7.54

(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, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $375 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 broad indicators 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 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 at market-based prices. 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 investments over a broad range of future prices. 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.

The Corporation has an active asset management program in which underperforming assets are either improved to acceptable levels or considered for divestment. The asset management program includes a disciplined, regular review to ensure that all assets are contributing to the Corporation's strategic objectives. The result is an efficient capital base, and the Corporation has seldom had 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. With respect to derivatives activities, the Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivatives described in note 12. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

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

The Corporation is exposed to changes in interest rates, primarily on its short-term debt and the portion of long-term debt that carries 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. Although the Corporation issues long-term debt from time to time and maintains a commercial paper program, internally generated funds are expected to cover the majority of its net near-term financial requirements. However, some joint-venture partners are dependent on the credit markets, and their funding ability may impact the development pace of joint-venture projects.

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 to mitigate the impact of changes in currency values, and exposures related to the Corporation's limited use of the currency exchange contracts are not material. The Corporation makes limited use of commodity forwards, swaps and futures contracts to mitigate the impact of changes in commodity prices. A substantial portion of the commodity futures contracts and swap agreements acquired as part of the XTO merger settled during 2010 and the majority of the remainder will settle by year-end 2011.

Inflation and Other Uncertainties

The general rate of inflation in many major countries of operation has remained moderate over the past few years, and the associated impact on non-energy costs has generally been mitigated by cost reductions from efficiency and productivity improvements. Increased demand for certain services and materials has resulted in higher operating and capital costs in recent years. The Corporation works to counter upward pressure on costs through its economies of scale in global procurement and its efficient project management practices.

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. 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 include both proved and unproved reserves. Consistent with the definitions in the Securities and Exchange Commission's Rule 4-10(a) of Regulation S-X, proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. 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 the Reserves Technical Oversight group which has significant technical experience, culminating in reviews with and approval by senior management. Notably, the Corporation does not use specific quantitative reserve targets to determine compensation.

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 reporting as proved.

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 was 69 percent of total proved reserves at year-end 2010 (including both consolidated and equity company reserves), and has been over 60 percent for the last five years, 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.

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, (2) new geologic, reservoir or production data or (3) changes in prices and costs that are used in the estimation of reserves. This category can also include 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. 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 actual volumes produced to total proved developed reserves (those proved reserves recoverable through existing wells with existing equipment and operating methods), applied to the 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. While the 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. 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. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

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 reserve volumes, an accumulation of project costs significantly in excess of the amount originally expected, and historical and forecast operating losses.

In general, the Corporation does not view temporarily low oil and gas 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 significantly, 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 price assumptions developed in the annual planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used

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

for capital investment decisions. Volumes are based on individual field production profiles, which are updated annually. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves is provided following the notes to consolidated financial statements. Future prices used for any impairment tests will vary from the one used in the supplemental oil and gas 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 2010 are disclosed in note 9 to the financial statements.

Consolidations

The Consolidated Financial Statements include the accounts of those subsidiaries that the Corporation controls. They also include the Corporation's share of the undivided interest in certain 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, advances and long-term receivables"; 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 non-consolidated 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.

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.

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.

Pension 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. Pension and Other Postretirement Benefits (note 16) 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 those in the United States, 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. Pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long-term expected earnings rate on U.S. pension plan assets in 2010 was 7.5 percent. The 10-year and 20-year actual returns on U.S. pension plan assets are 4 percent and 10 percent, respectively. 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 long-term rate of return on assets would increase annual pension expense by approximately $140 million before tax.

Differences between actual returns on fund assets and the long-term expected return are not recognized in pension expense in the year that the difference occurs. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected remaining service life of employees.

Litigation Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The status of significant claims is summarized in note 15.

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. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss.

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.

Tax Contingencies

The Corporation is subject to income taxation in many jurisdictions around the world. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict.

GAAP requires recognition and measurement of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns. The benefit of an uncertain tax position can only be recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken in an income tax return and the amount recognized in the financial statements. The Corporation’s unrecognized tax benefits and a description of open tax years are summarized in note 18.

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 use the local currency, except in countries with a history of high inflation (primarily in Latin America) and 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. Upstream operations using the U.S. dollar as their functional currency are primarily in Asia and Africa.

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; the history of inflation in the country; 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.

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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 criteria established in *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, 2010.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2010, as stated in their report included in the Financial Section of this report.

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

pwc

To the Shareholders of Exxon Mobil Corporation:

In our opinion, the accompanying Consolidated Balance Sheets and the related Consolidated Statements of Income, Comprehensive Income, Changes in Equity and Cash Flows present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidiaries at December 31, 2010, and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Corporation's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Corporation's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide 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.

/s/ PRICEWATERHOUSECOOPERS LLP

Dallas, Texas
February 25, 2011

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CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2010	2009	2008
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue [(1)]		$370,125	$301,500	$459,579
Income from equity affiliates	6	10,677	7,143	11,081
Other income [(2)]		2,419	1,943	6,699
Total revenues and other income		$383,221	$310,586	$477,359
Costs and other deductions				
Crude oil and product purchases		$197,959	$152,806	$249,454
Production and manufacturing expenses		35,792	33,027	37,905
Selling, general and administrative expenses		14,683	14,735	15,873
Depreciation and depletion		14,760	11,917	12,379
Exploration expenses, including dry holes		2,144	2,021	1,451
Interest expense		259	548	673
Sales-based taxes [(1)]	18	28,547	25,936	34,508
Other taxes and duties	18	36,118	34,819	41,719
Total costs and other deductions		$330,262	$275,809	$393,962
Income before income taxes		$ 52,959	$ 34,777	$ 83,397
Income taxes	18	21,561	15,119	36,530
Net income including noncontrolling interests		$ 31,398	$ 19,658	$ 46,867
Net income attributable to noncontrolling interests		938	378	1,647
Net income attributable to ExxonMobil		$ 30,460	$ 19,280	$ 45,220
Earnings per common share (dollars)	11	$ 6.24	$ 3.99	$ 8.70
Earnings per common share – assuming dilution (dollars)	11	$ 6.22	$ 3.98	$ 8.66

(1) Sales and other operating revenue includes sales-based taxes of $28,547 million for 2010, $25,936 million for 2009 and $34,508 million for 2008.
(2) Other income for 2008 includes a $62 million gain from the sale of a non-U.S. investment and a related $143 million foreign exchange loss.

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2010	Dec. 31 2009
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		$ 7,825	$ 10,693
Cash and cash equivalents – restricted	3	628	—
Marketable securities		2	169
Notes and accounts receivable, less estimated doubtful amounts	5	32,284	27,645
Inventories			
Crude oil, products and merchandise	3	9,852	8,718
Materials and supplies		3,124	2,835
Other current assets		5,269	5,175
Total current assets		$ 58,984	$ 55,235
Investments, advances and long-term receivables	7	35,338	31,665
Property, plant and equipment, at cost, less accumulated depreciation and depletion	8	199,548	139,116
Other assets, including intangibles, net		8,640	7,307
Total assets		$ 302,510	$ 233,323
Liabilities			
Current liabilities			
Notes and loans payable	5	$ 2,787	$ 2,476
Accounts payable and accrued liabilities	5	50,034	41,275
Income taxes payable		9,812	8,310
Total current liabilities		$ 62,633	$ 52,061
Long-term debt	13	12,227	7,129
Postretirement benefits reserves	16	19,367	17,942
Deferred income tax liabilities	18	35,150	23,148
Other long-term obligations		20,454	17,651
Total liabilities		$ 149,831	$ 117,931
Commitments and contingencies	15		
Equity			
Common stock without par value		$ 9,371	$ 5,503
(9,000 million shares authorized, 8,019 million shares issued)			
Earnings reinvested		298,899	276,937
Accumulated other comprehensive income			
Cumulative foreign exchange translation adjustment		5,011	4,402
Postretirement benefits reserves adjustment		(9,889)	(9,863)
Unrealized gain/(loss) on cash flow hedges		55	—
Common stock held in treasury (3,040 million shares in 2010 and 3,292 million shares in 2009)		(156,608)	(166,410)
ExxonMobil share of equity		$ 146,839	$ 110,569
Noncontrolling interests		5,840	4,823
Total equity		152,679	115,392
Total liabilities and equity		$ 302,510	$ 233,323

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2010	2009	2008
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		$ 31,398	$ 19,658	$ 46,867
Adjustments for noncash transactions				
Depreciation and depletion		14,760	11,917	12,379
Deferred income tax charges/(credits)		(1,135)	—	1,399
Postretirement benefits expense in excess of/(less than) net payments		1,700	(1,722)	57
Other long-term obligation provisions in excess of/(less than) payments		160	731	(63)
Dividends received greater than/(less than) equity in current earnings of equity companies		(596)	(483)	921
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) – Notes and accounts receivable		(5,863)	(3,170)	8,641
– Inventories		(1,148)	459	(1,285)
– Other current assets		913	132	(509)
Increase/(reduction) – Accounts and other payables		9,943	1,420	(5,415)
Net (gain) on asset sales	4	(1,401)	(488)	(3,757)
All other items – net		(318)	(16)	490
Net cash provided by operating activities		$ 48,413	$ 28,438	$ 59,725
Cash flows from investing activities				
Additions to property, plant and equipment		$(26,871)	$(22,491)	$(19,318)
Sales of subsidiaries, investments and property, plant and equipment	4	3,261	1,545	5,985
Decrease/(increase) in restricted cash and cash equivalents	3	(628)	—	—
Additional investments and advances		(1,239)	(2,752)	(2,495)
Collection of advances		1,133	724	574
Additions to marketable securities		(15)	(16)	(2,113)
Sales of marketable securities		155	571	1,868
Net cash used in investing activities		$(24,204)	$(22,419)	$(15,499)
Cash flows from financing activities				
Additions to long-term debt		$ 1,143	$ 225	$ 79
Reductions in long-term debt		(6,224)	(68)	(192)
Additions to short-term debt		598	1,336	1,067
Reductions in short-term debt		(2,436)	(1,575)	(1,624)
Additions/(reductions) in debt with three months or less maturity		709	(71)	143
Cash dividends to ExxonMobil shareholders		(8,498)	(8,023)	(8,058)
Cash dividends to noncontrolling interests		(281)	(280)	(375)
Changes in noncontrolling interests		(7)	(113)	(419)
Tax benefits related to stock-based awards		122	237	333
Common stock acquired		(13,093)	(19,703)	(35,734)
Common stock sold		1,043	752	753
Net cash used in financing activities		$(26,924)	$(27,283)	$(44,027)
Effects of exchange rate changes on cash		$ (153)	$ 520	$ (2,743)
Increase/(decrease) in cash and cash equivalents		$ (2,868)	$(20,744)	$ (2,544)
Cash and cash equivalents at beginning of year		10,693	31,437	33,981
Cash and cash equivalents at end of year		$ 7,825	$ 10,693	$ 31,437

Non-Cash Transactions

The Corporation acquired all the outstanding equity of XTO Energy Inc.
in an all-stock transaction valued at $24,659 million in 2010 (see note 19).

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

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CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Noncontrolling Interests	Total Equity
				(millions of dollars)			
Balance as of December 31, 2007	$ 4,933	$ 228,518	$ 1,989	$ (113,678)	$ 121,762	$ 4,282	$ 126,044
Amortization of stock-based awards	618				618		618
Tax benefits related to stock-based awards	315				315		315
Other	(552)				(552)		(552)
Net income for the year		45,220			45,220	1,647	46,867
Dividends – common shares		(8,058)			(8,058)	(375)	(8,433)
Foreign exchange translation adjustment			(6,964)		(6,964)	(334)	(7,298)
Adjustment for foreign exchange translation loss included in net income			138		138	17	155
Postretirement benefits reserves adjustment (note 16)			(5,853)		(5,853)	(224)	(6,077)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs (note 16)			759		759		759
Acquisitions, at cost				(35,734)	(35,734)	(675)	(36,409)
Dispositions				1,314	1,314	220	1,534
Balance as of December 31, 2008	$ 5,314	$ 265,680	$ (9,931)	$ (148,098)	$ 112,965	$ 4,558	$ 117,523
Amortization of stock-based awards	685				685		685
Tax benefits related to stock-based awards	140				140		140
Other	(636)				(636)		(636)
Net income for the year		19,280			19,280	378	19,658
Dividends – common shares		(8,023)			(8,023)	(280)	(8,303)
Foreign exchange translation adjustment			3,256		3,256	373	3,629
Postretirement benefits reserves adjustment (note 16)			(196)		(196)	(144)	(340)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs (note 16)			1,410		1,410	51	1,461
Acquisitions, at cost				(19,703)	(19,703)	(127)	(19,830)
Dispositions				1,391	1,391	14	1,405
Balance as of December 31, 2009	$ 5,503	$ 276,937	$ (5,461)	$ (166,410)	$ 110,569	$ 4,823	$ 115,392
Amortization of stock-based awards	751				751		751
Tax benefits related to stock-based awards	280				280		280
Other	(683)				(683)	10	(673)
Net income for the year		30,460			30,460	938	31,398
Dividends – common shares		(8,498)			(8,498)	(281)	(8,779)
Foreign exchange translation adjustment			584		584	450	1,034
Adjustment for foreign exchange translation loss included in net income			25		25		25
Postretirement benefits reserves adjustment (note 16)			(1,014)		(1,014)	(147)	(1,161)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs (note 16)			988		988	52	1,040
Change in fair value of cash flow hedges			184		184		184
Realized (gain)/loss from settled cash flow hedges included in net income			(129)		(129)		(129)
Acquisitions at cost				(13,093)	(13,093)	(5)	(13,098)
Issued for XTO merger	3,520			21,139	24,659		24,659
Other dispositions				1,756	1,756		1,756
Balance as of December 31, 2010	$ 9,371	$ 298,899	$ (4,823)	$ (156,608)	$ 146,839	$ 5,840	$ 152,679

The information in the Notes to Consolidated Financial Statements is an integral part of these statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY (continued)

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2007	8,019	(2,637)	5,382
Acquisitions		(434)	(434)
Dispositions		28	28
Balance as of December 31, 2008	8,019	(3,043)	4,976
Acquisitions		(277)	(277)
Dispositions		28	28
Balance as of December 31, 2009	8,019	(3,292)	4,727
Acquisitions		(199)	(199)
Issued for XTO merger		416	416
Other dispositions		35	35
Balance as of December 31, 2010	8,019	(3,040)	4,979

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2010	2009	2008
		(millions of dollars)	
Net income including noncontrolling interests	$31,398	$19,658	$46,867
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	1,034	3,629	(7,298)
Adjustment for foreign exchange translation loss included in net income	25	—	155
Postretirement benefits reserves adjustment (excluding amortization)	(1,161)	(340)	(6,077)
Amortization of postretirement benefits reserves adjustment included in net periodic benefit costs	1,040	1,461	759
Change in fair value of cash flow hedges	184	—	—
Realized (gain)/ loss from settled cash flow hedges included in net income	(129)	—	—
Comprehensive income including noncontrolling interests	32,391	24,408	34,406
Comprehensive income attributable to noncontrolling interests	1,293	658	1,106
Comprehensive income attributable to ExxonMobil	$31,098	$23,750	$33,300

The information in the Notes to Consolidated Financial Statements 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. Prior years' data has been reclassified in certain cases to conform to the 2010 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation. The Consolidated Financial Statements include the accounts of those 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 certain upstream assets and liabilities.

Amounts representing the Corporation's percentage interest in the underlying net assets of other subsidiaries and less-than-majority-owned companies in which a significant ownership percentage interest is held are included in "Investments, advances and long-term receivables"; 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 the Consolidated Statement of Changes in 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.

Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another are combined and recorded as exchanges measured at the book value of the item sold.

Sales-Based Taxes. The Corporation reports sales, excise and value-added taxes on sales transactions on a gross basis in the Consolidated Statement of Income (included in both revenues and costs). This gross reporting basis is footnoted on the Consolidated Statement of Income.

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 forecasted transactions. For derivatives designated as cash flow hedges, the Corporation's activity is intended to manage the price risk posed by physical transactions.

The Corporation records all derivatives on the balance sheet at fair value. The change in fair value of derivatives designated as fair value hedges is recognized in earnings, offset by the change in fair value of the hedged item. The change in fair value of derivatives designated as cash flow hedges is recorded in other comprehensive income and recognized in earnings when the hedged transaction is recognized in earnings. The change in fair value of derivatives not designated as hedging instruments is recognized in earnings. Any ineffectiveness between the derivative and the hedged item is recorded in earnings.

Hedge effectiveness is reviewed at least quarterly and is generally based on the most recent relevant correlation between the derivative and the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

item hedged. Hedge ineffectiveness is calculated based on the difference between the change in fair value of the derivative and change in cash flow or fair value of the items hedged. If it is determined that a derivative is no longer highly effective, hedge accounting is then discontinued and the change in fair value since inception that is on the balance sheet either as other comprehensive income for cash flow hedges, or the underlying hedged item for fair value hedges, is recorded in earnings.

Fair Value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 or 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

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.

Interest costs incurred to finance expenditures during the construction phase of multiyear projects are capitalized as part of the historical cost of acquiring the constructed assets. The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use. Capitalized interest costs are included in property, plant and equipment and are depreciated over the service life of the related assets.

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.

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. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period. 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 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.

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

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

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

Goodwill. Goodwill is the excess of the consideration transferred over the value of net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill is evaluated for impairment on at least an annual basis.

Asset Retirement Obligations and Environmental Liabilities. The Corporation incurs retirement obligations for certain assets at the time they are installed. The fair values of these obligations are recorded as liabilities on a discounted basis. The costs associated with these liabilities are capitalized as part of the related assets and depreciated. Over time, the liabilities are accreted for the change in their present value.

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 Corporation selects the functional reporting currency for its international subsidiaries based on the currency of the primary economic environment in which each subsidiary operates. Downstream and Chemical operations primarily use the local currency. However, the U.S. dollar is used in countries with a history of high inflation (primarily in Latin America) and Singapore, which predominantly sells into the U.S. dollar export market. Upstream operations which are relatively self-contained and integrated within a particular country, such as Canada, the United Kingdom, Norway and continental Europe, use the local currency. Some Upstream operations, primarily in Asia and Africa, use the U.S. dollar because they predominantly sell crude and natural gas production into U.S. dollar-denominated markets. For all operations, gains or losses from remeasuring foreign currency transactions into the functional currency are included in income.

Stock-Based Payments. The Corporation awards stock-based compensation to employees in the form of restricted stock and restricted stock units. Compensation expense is measured by the market price of the restricted shares at the date of grant and is recognized in the income statement over the requisite service period of each award. See note 14, Incentive Program, for further details.

2. Accounting Changes

Variable-Interest Entities. Effective January 1, 2010, ExxonMobil adopted the authoritative guidance for variable-interest entities (VIEs). The guidance requires the enterprise to qualitatively assess if it is the primary beneficiary of the VIE and, if so, the VIE must be consolidated. The adoption of the guidance did not have a material impact on the Corporation’s financial statements.

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3. Miscellaneous Financial Information

Research and development costs totaled $1,012 million in 2010, $1,050 million in 2009 and $847 million in 2008.

Net income included before-tax aggregate foreign exchange transaction losses of $251 million, and gains of $54 million and $54 million in 2010, 2009 and 2008, respectively.

In 2010, 2009 and 2008, net income included gains of $317 million, $207 million and $341 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 $21.3 billion and $17.1 billion at December 31, 2010, and 2009, respectively.

Crude oil, products and merchandise as of year-end 2010 and 2009 consist of the following:

	2010	2009
	(billions of dollars)	
Petroleum products	$ 3.5	$ 3.2
Crude oil	3.8	3.2
Chemical products	2.1	2.0
Gas/other	0.5	0.3
Total	$ 9.9	$ 8.7

The December 31, 2010, total cash and cash equivalents balance of $8,453 million includes $628 million of restricted funds.

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.

The “Net (gain) on asset sales” in net cash provided by operating activities on the Consolidated Statement of Cash Flows includes before-tax gains from the sale of some Upstream Gulf of Mexico and other producing properties, the sale of U.S. service stations and other Downstream assets and investments and the formation of a Chemical joint venture in 2010; from the sale of Downstream assets and investments and producing properties in the Upstream in 2009; and from the sale of a natural gas transportation business in Germany and other producing properties in the Upstream and Downstream assets and investments in 2008. These gains are reported in “Other income” on the Consolidated Statement of Income.

	2010	2009	2008
		(millions of dollars)	
Cash payments for interest	$ 703	$ 820	$ 650
Cash payments for income taxes	$18,941	$15,427	$33,941

5. Additional Working Capital Information

	Dec. 31 2010	Dec. 31 2009
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $152 million and $198 million	$25,439	$22,186
Other, less reserves of $34 million and $31 million	6,845	5,459
Total	$32,284	$27,645
Notes and loans payable		
Bank loans	$ 532	$ 1,043
Commercial paper	1,346	201
Long-term debt due within one year	345	348
Other	564	884
Total	$ 2,787	$ 2,476
Accounts payable and accrued liabilities		
Trade payables	$30,780	$24,236
Payables to equity companies	5,450	4,979
Accrued taxes other than income taxes	6,778	5,921
Other	7,026	6,139
Total	$50,034	$41,275

On December 31, 2010, unused credit lines for short-term financing totaled approximately $5.6 billion. Of this total, $2.8 billion support commercial paper programs under terms negotiated when drawn. The weighted-average interest rate on short-term borrowings outstanding at December 31, 2010, and 2009, was 1.2 percent and 3.6 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). 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 liquefied natural gas (LNG) operations in Qatar. Also included are several power generation, refining, petrochemical 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 equity company revenues from sales to ExxonMobil consolidated companies was 18 percent, 19 percent and 21 percent in the years 2010, 2009 and 2008, respectively.

Equity Company Financial Summary	2010 Total	2010 ExxonMobil Share	2009 Total	2009 ExxonMobil Share	2008 Total	2008 ExxonMobil Share
			(millions of dollars)			
Total revenues	$153,020	$ 48,355	$112,153	$ 36,570	$148,477	$ 49,999
Income before income taxes	$ 48,075	$ 14,735	$ 28,472	$ 9,632	$ 42,588	$ 15,082
Income taxes	13,962	4,058	7,775	2,489	12,020	4,001
Income from equity affiliates	$ 34,113	$ 10,677	$ 20,697	$ 7,143	$ 30,568	$ 11,081
Current assets	$ 48,573	$ 15,860	$ 37,376	$ 12,843	$ 29,358	$ 9,920
Long-term assets	90,646	29,805	88,153	27,983	87,442	28,339
Total assets	$139,219	$ 45,665	$125,529	$ 40,826	$116,800	$ 38,259
Current liabilities	$ 33,160	$ 10,260	$ 24,854	$ 8,085	$ 26,221	$ 8,707
Long-term liabilities	59,596	17,976	57,384	16,999	50,895	15,094
Net assets	$ 46,463	$ 17,429	$ 43,291	$ 15,742	$ 39,684	$ 14,458

A list of significant equity companies as of December 31, 2010, 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
Golden Pass LNG Terminal LLC	18
Nederlandse Aardolie Maatschappij B.V.	50
Qatar Liquefied Gas Company Limited	10
Qatar Liquefied Gas Company Limited 2	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited II	31
Ras Laffan Liquefied Natural Gas Company Limited (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	69
Downstream	
Chalmette Refining, LLC	50
Fujian Refining & Petrochemical Co. Ltd.	25
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Infineum Holdings B.V.	50
Saudi Yanbu Petrochemical Co.	50
Toray Tonen Specialty Separator Godo Kaisha	50

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7. Investments, Advances and Long-Term Receivables

	Dec 31 2010	Dec 31 2009
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	$17,429	$15,742
Advances	9,286	8,669
	$26,715	$24,411
Companies carried at cost or less and stock investments carried at fair value	1,557	1,577
	$28,272	$25,988
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $292 million and $368 million	7,066	5,677
Total	$35,338	$31,665

8. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	Dec. 31, 2010		Dec. 31, 2009	
	Cost	Net	Cost	Net
	(millions of dollars)			
Upstream	$264,136	$148,152	$198,036	$ 88,319
Downstream	68,652	30,095	68,092	30,499
Chemical	29,524	14,255	28,464	13,511
Other	11,626	7,046	11,314	6,787
Total	$373,938	$199,548	$305,906	$139,116

In the Upstream segment, depreciation is generally 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 $174,390 million at the end of 2010 and $166,790 million at the end of 2009. Interest capitalized in 2010, 2009 and 2008 was $532 million, $425 million and $510 million, respectively.

Asset Retirement Obligations

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 Corporation uses estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; technical assessments of the assets; estimated amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. AROs incurred in the current period were Level 3 (unobservable inputs) fair value measurements. 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 their present value. Asset retirement obligations for downstream and chemical facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations and as such, the fair value of the conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations.

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

	2010	2009
	(millions of dollars)	
Beginning balance	$8,473	$5,352
Accretion expense and other provisions	563	372
Reduction due to property sales	(183)	(18)
Payments made	(638)	(448)
Liabilities incurred	1,094	156
Foreign currency translation	(45)	535
Revisions	350	2,524
Ending balance	$9,614	$8,473

9. Accounting for Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs beyond one year after the well is completed if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress is being made in assessing the reserves and the economic and operating viability of the project.

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:

	2010	2009	2008
		(millions of dollars)	
Balance beginning at January 1	$2,005	$1,585	$1,291
Additions pending the determination of proved reserves	1,103	624	448
Charged to expense	(104)	(51)	—
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(136)	(200)	(101)
Other	25	47	(53)
Ending balance	$2,893	$2,005	$1,585
Ending balance attributed to equity companies included above	$ —	$ 9	$ 10

Period end capitalized suspended exploratory well costs:

	2010	2009	2008
		(millions of dollars)	
Capitalized for a period of one year or less	$1,103	$ 624	$ 448
Capitalized for a period of between one and five years	1,294	924	636
Capitalized for a period of between five and ten years	278	220	225
Capitalized for a period of greater than ten years	218	237	276
Capitalized for a period greater than one year – subtotal	$1,790	$1,381	$1,137
Total	$2,893	$2,005	$1,585

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.

	2010	2009	2008
Number of projects with first capitalized well drilled in the preceding 12 months	9	18	12
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	59	57	50
Total	68	75	62

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Of the 59 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2010, 25 projects have drilling in the preceding 12 months or exploratory activity planned in the next two years, while the remaining 34 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 34 projects, which total $692 million.

Country/Project	Dec. 31, 2010 *(millions of dollars)*	Years Wells Drilled	Comment
Angola			
- Perpetua-Zina-Acacia	$ 15	2008 - 2009	Oil field near Pazflor development, awaiting capacity in existing/planned infrastructure.
Australia			
- East Pilchard	10	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/planned infrastructure.
Indonesia			
- Natuna	118	1981 - 1983	Development activity under way, while continuing discussions with the government on contract terms pursuant to recently executed Heads of Agreement.
Kazakhstan			
- Kairan	53	2004 - 2007	Declarations involving field commerciality filed with Kazakhstan government in 2008; progressing commercialization and field development studies.
Nigeria			
- Bolia	15	2002 - 2006	Evaluating development plan, while continuing discussions with the government regarding regional hub strategy.
- Bonga North	34	2004 - 2009	Pursuing alignment with operator and government regarding development plan.
- Bosi	79	2002 - 2006	Development activity under way while continuing discussions with the government regarding development plan.
- Other (5 projects)	16	2001 - 2002	Pursuing development of several additional offshore satellite discoveries which will tie back to existing/planned production facilities.
Norway			
- Gamma	20	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- H-North	15	2007	Discovery near existing facilities in Fram area; evaluating development options.
- Lavrans	23	1995 - 1999	Development awaiting capacity in existing Kristin production facility; evaluating development concepts for phased ullage scenarios.
- Noatun	19	2008	Evaluating development plan for tieback to existing production facilities.
- Nyk High	20	2008	Evaluating field development alternatives.
- Other (8 projects)	34	1992 - 2009	Evaluating development plans, including potential for tieback to existing production facilities.
Papua New Guinea			
- Juha	28	2007	Working on development plans to tie into planned LNG facilities.
United Kingdom			
- Fram	55	2009	Progressing development and commercialization plans.
- Other (3 projects)	21	2001 - 2008	Projects primarily awaiting capacity in existing or planned infrastructure.
United States			
- Julia Unit	78	2007 - 2008	Julia Unit owners are progressing development plans and have agreed to share funding on facilities at the Chevron-operated Jack-Saint Malo platform. Suspension of Production for the Julia Unit is under review by the Bureau of Ocean Energy Management, Regulation and Enforcement.
- Tip Top	31	2009	Evaluating development concept and requisite facility upgrades.
Other			
- Various (2 projects)	8	1979 - 1995	Projects primarily awaiting capacity in existing or planned infrastructure.
Total 2010 (34 projects)	$ 692		

10. Leased Facilities

At December 31, 2010, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering drilling equipment, tankers, service stations and other properties with minimum undiscounted lease commitments totaling $7,776 million as indicated in the table. Estimated related rental income from noncancelable subleases is $62 million.

	Lease Payments Under Minimum Commitments	Related Sublease Rental Income
	(millions of dollars)	
2011	$ 2,095	$ 8
2012	1,570	8
2013	1,061	7
2014	731	6
2015	581	6
2016 and beyond	1,738	27
Total	$ 7,776	$ 62

Net rental cost under both cancelable and noncancelable operating leases incurred during 2010, 2009 and 2008 were as follows:

	2010	2009	2008
		(millions of dollars)	
Rental cost	$3,762	$4,426	$4,115
Less sublease rental income	90	98	123
Net rental cost	$3,672	$4,328	$3,992

11. Earnings Per Share

	2010	2009	2008
Earnings per common share			
Net income attributable to ExxonMobil *(millions of dollars)*	$30,460	$19,280	$45,220
Weighted average number of common shares outstanding *(millions of shares)*	4,885	4,832	5,194
Earnings per common share *(dollars)*	$ 6.24	$ 3.99	$ 8.70
Earnings per common share – assuming dilution			
Net income attributable to ExxonMobil *(millions of dollars)*	$30,460	$19,280	$45,220
Weighted average number of common shares outstanding *(millions of shares)*	4,885	4,832	5,194
Effect of employee stock-based awards	12	16	27
Weighted average number of common shares outstanding – assuming dilution	4,897	4,848	5,221
Earnings per common share – assuming dilution *(dollars)*	$ 6.22	$ 3.98	$ 8.66
Dividends paid per common share *(dollars)*	$ 1.74	$ 1.66	$ 1.55

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

12. Financial Instruments and Derivatives

Financial Instruments. The fair value of financial instruments is determined by reference to observable market data and other valuation techniques as appropriate. The only category of financial instruments where the difference between fair value and recorded book value is notable is long-term debt. The estimated fair value of total long-term debt, including capitalized lease obligations, was $12.8 billion and $7.7 billion at December 31, 2010, and 2009, respectively, as compared to recorded book values of $12.2 billion and $7.1 billion at December 31, 2010, and 2009, respectively. The fair value hierarchy for long-term debt is primarily Level 1 (quoted prices for identical assets in active markets).

Derivative Instruments. 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.

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 forecasted transactions. For derivatives designated as cash flow hedges, the Corporation's activity is intended to manage the price risk posed by physical transactions.

The estimated fair value of derivative instruments outstanding and recorded on the balance sheet was a net asset of $172 million at year-end 2010 and a net liability of $5 million at year-end 2009. This is the amount that the Corporation would have received from, or paid to, third parties if these derivatives had been settled in the open market. Assets and liabilities associated with derivatives are predominantly recorded either in "Other current assets" or "Accounts payable and accrued liabilities." The year-end 2010 net asset balance includes the Corporation's outstanding cash flow hedge position, acquired as a result of the XTO merger, of $219 million. As the current cash flow hedge positions settle, these programs will be discontinued.

The Corporation's fair value measurement of its derivative instruments uses primarily Level 2 inputs (derivatives that are determined by either market prices on an active market for similar assets or by prices quoted by a broker or other market-corroborated prices).

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of $221 million, $(73) million and $154 million during 2010, 2009 and 2008, respectively. Income statement effects associated with derivatives are recorded either in "Sales and other operating revenue" or "Crude oil and product purchases." Of the amount stated above for 2010, cash flow hedges resulted in a before-tax gain of $218 million. The ineffective portion of derivatives designated as hedges is de minimis.

The principal natural gas futures contracts and swap agreements acquired as part of the XTO merger that are in place as of December 31, 2010, will expire by the end of 2011. The associated volume of natural gas is 250 mcfd at a weighted average NYMEX price of $7.02 per thousand cubic feet. These derivative contracts qualify for cash flow hedge accounting. The Corporation will receive the cash flow related to these derivative contracts at the price indicated above. However, the amount of the income statement gain or loss realized from these contracts will be limited to the change in fair value of the derivative instruments from the acquisition date of XTO.

The Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivative activities described above. The fair value of derivatives outstanding at year-end 2010 and the gain recognized during the year are immaterial.

13. Long-term Debt

At December 31, 2010, long-term debt consisted of $11,610 million due in U.S. dollars and $617 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 $345 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, 2011, in millions of dollars, are: 2012 – $3,222, 2013 – $1,019, 2014 – $622 and 2015 – $601. At December 31, 2010, the Corporation's unused long-term credit lines were not material.

Summarized long-term debt at year-end 2010 and 2009 are shown in the table below:

	2010	2009
	(millions of dollars)	
SeaRiver Maritime Financial Holdings, Inc. *(1)*		
Guaranteed debt securities due 2011 *(2)*	$ —	$ 13
Guaranteed deferred interest debentures due 2012		
– Face value net of unamortized discount plus accrued interest	2,389	2,144
XTO Energy Inc. (premium in millions of dollars)		
7.500% senior note due 2012 includes premium of $15	199	—
5.900% senior note due 2012 includes premium of $16	233	—
6.250% senior note due 2013 includes premium of $18	193	—
4.625% senior note due 2013 includes premium of $9	149	—
5.750% senior note due 2013 includes premium of $37	359	—
4.900% senior note due 2014 includes premium of $19	267	—
5.000% senior note due 2015 includes premium of $13	142	—
5.300% senior note due 2015 includes premium of $28	262	—
5.650% senior note due 2016 includes premium of $27	227	—
6.250% senior note due 2017 includes premium of $80	534	—
5.500% senior note due 2018 includes premium of $49	420	—
6.500% senior note due 2018 includes premium of $86	524	—
6.100% senior note due 2036 includes premium of $29	204	—
6.750% senior note due 2037 includes premium of $69	329	—
6.375% senior note due 2038 includes premium of $46	258	—
Mobil Services (Bahamas) Ltd.		
Variable note due 2035 *(3)*	972	972
Variable note due 2034 *(4)*	311	311
Mobil Producing Nigeria Unlimited *(5)*		
Variable notes due 2012-2017	415	621
Esso (Thailand) Public Company Ltd. *(6)*		
Variable notes due 2012-2017	522	165
Mobil Corporation		
8.625% debentures due 2021	248	248
Industrial revenue bonds due 2012-2040 *(7)*	2,247	1,685
Other U.S. dollar obligations *(8)*	454	536
Other foreign currency obligations	65	66
Capitalized lease obligations *(9)*	304	368
Total long-term debt	$12,227	$7,129

(1) Additional information is provided for this subsidiary on the following pages.
(2) Average effective interest rate of 1.6% in 2009.
(3) Average effective interest rate of 0.3% in 2010 and 0.3% in 2009.
(4) Average effective interest rate of 0.4% in 2010 and 0.9% in 2009.
(5) Average effective interest rate of 4.6% in 2010 and 5.4% in 2009.
(6) Average effective interest rate of 1.7% in 2010 and 2.2% in 2009.
(7) Average effective interest rate of 0.2% in 2010 and 0.2% in 2009.
(8) Average effective interest rate of 4.7% in 2010 and 5.0% in 2009.
(9) Average imputed interest rate of 8.1% in 2010 and 8.8% in 2009.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

Exxon Mobil Corporation has fully and unconditionally guaranteed the deferred interest debentures due 2012 ($2,389 million long-term debt at December 31, 2010) and the debt securities due 2011 ($13 million short-term) of SeaRiver Maritime Financial Holdings, Inc.

SeaRiver Maritime Financial Holdings, Inc. is a 100-percent-owned subsidiary of Exxon Mobil Corporation.

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

	Exxon Mobil Corporation Parent Guarantor	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, 2010					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$ 15,382	$ —	$354,743	$ —	$ 370,125
Income from equity affiliates	28,401	(2)	10,589	(28,311)	10,677
Other income	790	—	1,629	—	2,419
Intercompany revenue	39,433	4	332,483	(371,920)	—
Total revenues and other income	84,006	2	699,444	(400,231)	383,221
Costs and other deductions					
Crude oil and product purchases	40,788	—	518,961	(361,790)	197,959
Production and manufacturing expenses	7,627	—	33,400	(5,235)	35,792
Selling, general and administrative expenses	2,871	—	12,482	(670)	14,683
Depreciation and depletion	1,761	—	12,999	—	14,760
Exploration expenses, including dry holes	251	—	1,893	—	2,144
Interest expense	217	246	4,035	(4,239)	259
Sales-based taxes	—	—	28,547	—	28,547
Other taxes and duties	29	—	36,089	—	36,118
Total costs and other deductions	53,544	246	648,406	(371,934)	330,262
Income before income taxes	30,462	(244)	51,038	(28,297)	52,959
Income taxes	2	(90)	21,649	—	21,561
Net income including noncontrolling interests	30,460	(154)	29,389	(28,297)	31,398
Net income attributable to noncontrolling interests	—	—	938	—	938
Net income attributable to ExxonMobil	$ 30,460	$ (154)	$ 28,451	$ (28,297)	$ 30,460

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries (millions of dollars)	Consolidating and Eliminating Adjustments	Consolidated
Condensed consolidated statement of income for 12 months ended December 31, 2009					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$ 11,352	$ —	$290,148	$ —	$ 301,500
Income from equity affiliates	19,852	7	7,060	(19,776)	7,143
Other income	813	—	1,130	—	1,943
Intercompany revenue	30,889	4	271,663	(302,556)	—
Total revenues and other income	62,906	11	570,001	(322,332)	310,586
Costs and other deductions					
Crude oil and product purchases	31,419	—	411,689	(290,302)	152,806
Production and manufacturing expenses	7,811	—	30,805	(5,589)	33,027
Selling, general and administrative expenses	2,574	—	12,852	(691)	14,735
Depreciation and depletion	1,571	—	10,346	—	11,917
Exploration expenses, including dry holes	230	—	1,791	—	2,021
Interest expense	1,200	222	5,126	(6,000)	548
Sales-based taxes	—	—	25,936	—	25,936
Other taxes and duties	(29)	—	34,848	—	34,819
Total costs and other deductions	44,776	222	533,393	(302,582)	275,809
Income before income taxes	18,130	(211)	36,608	(19,750)	34,777
Income taxes	(1,150)	(81)	16,350	—	15,119
Net income including noncontrolling interests	19,280	(130)	20,258	(19,750)	19,658
Net income attributable to noncontrolling interests	—	—	378	—	378
Net income attributable to ExxonMobil	$ 19,280	$ (130)	$ 19,880	$ (19,750)	$ 19,280
Condensed consolidated statement of income for 12 months ended December 31, 2008					
Revenues and other income					
Sales and other operating revenue, including sales-based taxes	$ 17,481	$ —	$442,098	$ —	$ 459,579
Income from equity affiliates	45,664	9	11,055	(45,647)	11,081
Other income	302	—	6,397	—	6,699
Intercompany revenue	48,414	45	442,305	(490,764)	—
Total revenues and other income	111,861	54	901,855	(536,411)	477,359
Costs and other deductions					
Crude oil and product purchases	48,346	—	669,107	(467,999)	249,454
Production and manufacturing expenses	8,327	—	35,298	(5,720)	37,905
Selling, general and administrative expenses	3,349	—	13,364	(840)	15,873
Depreciation and depletion	1,552	—	10,827	—	12,379
Exploration expenses, including dry holes	192	—	1,259	—	1,451
Interest expense	3,859	207	13,143	(16,536)	673
Sales-based taxes	—	—	34,508	—	34,508
Other taxes and duties	67	—	41,652	—	41,719
Total costs and other deductions	65,692	207	819,158	(491,095)	393,962
Income before income taxes	46,169	(153)	82,697	(45,316)	83,397
Income taxes	949	(56)	35,637	—	36,530
Net income including noncontrolling interests	45,220	(97)	47,060	(45,316)	46,867
Net income attributable to noncontrolling interests	—	—	1,647	—	1,647
Net income attributable to ExxonMobil	$ 45,220	$ (97)	$ 45,413	$ (45,316)	$ 45,220

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Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	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, 2010					
Cash and cash equivalents	$ 309	$ —	$ 7,516	$ —	$ 7,825
Cash and cash equivalents – restricted	371	—	257	—	628
Marketable securities	—	—	2	—	2
Notes and accounts receivable – net	2,104	—	30,346	(166)	32,284
Inventories	1,457	—	11,519	—	12,976
Other current assets	239	—	5,030	—	5,269
Total current assets	4,480	—	54,670	(166)	58,984
Investments, advances and long-term receivables	254,781	446	454,489	(674,378)	35,338
Property, plant and equipment – net	18,830	—	180,718	—	199,548
Other long-term assets	224	12	8,404	—	8,640
Intercompany receivables	18,186	2,457	528,405	(549,048)	—
Total assets	$ 296,501	$ 2,915	$1,226,686	$(1,223,592)	$ 302,510
Notes and loans payable	$ 1,042	$ 13	$ 1,732	$ —	$ 2,787
Accounts payable and accrued liabilities	2,987	—	47,047	—	50,034
Income taxes payable	—	3	9,975	(166)	9,812
Total current liabilities	4,029	16	58,754	(166)	62,633
Long-term debt	295	2,389	9,543	—	12,227
Postretirement benefits reserves	9,660	—	9,707	—	19,367
Deferred income tax liabilities	642	107	34,401	—	35,150
Other long-term liabilities	5,632	—	14,822	—	20,454
Intercompany payables	129,404	382	419,262	(549,048)	—
Total liabilities	149,662	2,894	546,489	(549,214)	149,831
Earnings reinvested	298,899	(848)	132,357	(131,509)	298,899
Other equity	(152,060)	869	542,000	(542,869)	(152,060)
ExxonMobil share of equity	146,839	21	674,357	(674,378)	146,839
Noncontrolling interests	—	—	5,840	—	5,840
Total equity	146,839	21	680,197	(674,378)	152,679
Total liabilities and equity	$ 296,501	$ 2,915	$1,226,686	$(1,223,592)	$ 302,510
Condensed consolidated balance sheet for year ended December 31, 2009					
Cash and cash equivalents	$ 449	$ —	$ 10,244	$ —	$ 10,693
Marketable securities	—	—	169	—	169
Notes and accounts receivable – net	2,050	—	25,858	(263)	27,645
Inventories	1,202	—	10,351	—	11,553
Other current assets	313	—	4,862	—	5,175
Total current assets	4,014	—	51,484	(263)	55,235
Investments, advances and long-term receivables	199,110	449	439,712	(607,606)	31,665
Property, plant and equipment – net	18,015	—	121,101	—	139,116
Other long-term assets	207	24	7,076	—	7,307
Intercompany receivables	19,637	2,257	442,903	(464,797)	—
Total assets	$ 240,983	$ 2,730	$1,062,276	$(1,072,666)	$ 233,323
Notes and loans payable	$ 43	$ 13	$ 2,420	$ —	$ 2,476
Accounts payable and accrued liabilities	2,779	—	38,496	—	41,275
Income taxes payable	—	2	8,571	(263)	8,310
Total current liabilities	2,822	15	49,487	(263)	52,061
Long-term debt	279	2,157	4,693	—	7,129
Postretirement benefits reserves	8,673	—	9,269	—	17,942
Deferred income tax liabilities	818	151	22,179	—	23,148
Other long-term liabilities	5,286	—	12,365	—	17,651
Intercompany payables	112,536	382	351,879	(464,797)	—
Total liabilities	130,414	2,705	449,872	(465,060)	117,931
Earnings reinvested	276,937	(694)	109,603	(108,909)	276,937
Other equity	(166,368)	719	497,978	(498,697)	(166,368)
ExxonMobil share of equity	110,569	25	607,581	(607,606)	110,569
Noncontrolling interests	—	—	4,823	—	4,823
Total equity	110,569	25	612,404	(607,606)	115,392
Total liabilities and equity	$ 240,983	$ 2,730	$1,062,276	$(1,072,666)	$ 233,323

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc	All Other Subsidiaries (millions of dollars)	Consolidating and Eliminating Adjustments	Consolidated
Condensed consolidated statement of cash flows for 12 months ended December 31, 2010					
Cash provided by/(used in) operating activities	$ 35,740	$ 63	$ 18,307	$ (5,697)	$ 48,413
Cash flows from investing activities					
Additions to property, plant and equipment	(2,922)	—	(23,949)	—	(26,871)
Sales of long-term assets	1,484	—	1,777	—	3,261
Decrease/(increase) in restricted cash and cash equivalents	(371)	—	(257)	—	(628)
Net intercompany investing	(13,966)	(200)	13,813	353	—
All other investing, net	(672)	—	706	—	34
Net cash provided by/(used in) investing activities	(16,447)	(200)	(7,910)	353	(24,204)
Cash flows from financing activities					
Additions to short- and long-term debt	—	—	1,741	—	1,741
Reductions in short- and long-term debt	(3)	(13)	(8,644)	—	(8,660)
Additions/(reductions) in debt with three months or less maturity	997	—	(288)	—	709
Cash dividends	(8,498)	—	(5,697)	5,697	(8,498)
Common stock acquired	(13,093)	—	—	—	(13,093)
Net intercompany financing activity	—	—	202	(202)	—
All other financing, net	1,164	150	(286)	(151)	877
Net cash provided by/(used in) financing activities	(19,433)	137	(12,972)	5,344	(26,924)
Effects of exchange rate changes on cash	—	—	(153)	—	(153)
Increase/(decrease) in cash and cash equivalents	$ (140)	$ —	$ (2,728)	$ —	$ (2,868)
Condensed consolidated statement of cash flows for 12 months ended December 31, 2009					
Cash provided by/(used in) operating activities	$ 27,424	$ 72	$ 28,024	$ (27,082)	$ 28,438
Cash flows from investing activities					
Additions to property, plant and equipment	(2,686)	—	(19,805)	—	(22,491)
Sales of long-term assets	228	—	1,317	—	1,545
Decrease/(increase) in restricted cash and cash equivalents	—	—	—	—	—
Net intercompany investing	(1,826)	(209)	1,717	318	—
All other investing, net	—	—	(1,473)	—	(1,473)
Net cash provided by/(used in) investing activities	(4,284)	(209)	(18,244)	318	(22,419)
Cash flows from financing activities					
Additions to short- and long-term debt	—	—	1,561	—	1,561
Reductions in short- and long-term debt	(3)	(13)	(1,627)	—	(1,643)
Additions/(reductions) in debt with three months or less maturity	39	—	(110)	—	(71)
Cash dividends	(8,023)	—	(27,082)	27,082	(8,023)
Common stock acquired	(19,703)	—	—	—	(19,703)
Net intercompany financing activity	—	—	168	(168)	—
All other financing, net	988	150	(392)	(150)	596
Net cash provided by/(used in) financing activities	(26,702)	137	(27,482)	26,764	(27,283)
Effects of exchange rate changes on cash	—	—	520	—	520
Increase/(decrease) in cash and cash equivalents	$ (3,562)	$ —	$ (17,182)	$ —	$ (20,744)

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Condensed consolidating financial information related to guaranteed securities issued by subsidiaries

	Exxon Mobil Corporation Parent Guarantor	SeaRiver Maritime Financial Holdings, Inc.	All Other Subsidiaries (millions of dollars)	Consolidating and Eliminating Adjustments	Consolidated
Condensed consolidated statement of cash flows for 12 months ended December 31, 2008					
Cash provided by/(used in) operating activities	$ 47,823	$ 68	$ 54,478	$ (42,644)	$ 59,725
Cash flows from investing activities					
Additions to property, plant and equipment	(2,154)	—	(17,164)	—	(19,318)
Sales of long-term assets	162	—	5,823	—	5,985
Decrease/(increase) in restricted cash and cash equivalents	—	—	—	—	—
Net intercompany investing	(502)	(155)	476	181	—
All other investing, net	—	—	(2,166)	—	(2,166)
Net cash provided by/(used in) investing activities	(2,494)	(155)	(13,031)	181	(15,499)
Cash flows from financing activities					
Additions to short- and long-term debt	—	—	1,146	—	1,146
Reductions in short- and long-term debt	(4)	(13)	(1,799)	—	(1,816)
Additions/(reductions) in debt with three months or less maturity	—	—	143	—	143
Cash dividends	(8,058)	—	(42,644)	42,644	(8,058)
Common stock acquired	(35,734)	—	—	—	(35,734)
Net intercompany financing activity	—	—	81	(81)	—
All other financing, net	1,085	100	(793)	(100)	292
Net cash provided by/(used in) financing activities	(42,711)	87	(43,866)	42,463	(44,027)
Effects of exchange rate changes on cash	—	—	(2,743)	—	(2,743)
Increase/(decrease) in cash and cash equivalents	$ 2,618	$ —	$ (5,162)	$ —	$ (2,544)

14. 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. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. 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. At the end of 2010, remaining shares available for award under the 2003 Incentive Program were 141,939 thousand.

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 either granted prior to 2002 or were converted XTO stock options as a result of the XTO merger.

Under the terms of the XTO merger agreement, outstanding XTO stock-based awards were converted into ExxonMobil stock-based awards based on the merger exchange ratio. The converted XTO awards, granted under XTO’s 1998 or 2004 Stock Incentive Plans, include restricted stock awards, stock options and performance stock awards. The grant date for the converted XTO awards is considered to be the effective date of the merger for purposes of calculating fair value. Compensation cost for the converted XTO awards is recognized in income over the requisite service period. The maximum term of the XTO awards is ten years under the 1998 plan and seven years under the 2004 plan. No additional awards will be issued under either XTO plan. In connection with the closing of the merger, the Corporation also made new grants of restricted stock under the Corporation’s 2003 Incentive Program to certain current or former XTO employees as described in more detail below.

Restricted Stock. Excluding XTO merger-related grants, long-term incentive awards totaling 10,648 thousand of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2010. Awards totaling 10,133 thousand and 10,116 thousand of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2009 and 2008, 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 senior executives have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

Additionally, long-term incentive awards totaling 4,206 thousand of restricted (nonvested) common stock were granted in 2010 in association with the XTO merger. This included the granting of 1,423 thousand of restricted common stock awards under the Corporation's 2003 Incentive Program and 2,783 thousand of converted XTO restricted common stock awards. The majority of the converted XTO awards vest in three installments over a period of three years or three and a half years after the initial grant. The remainder of converted XTO awards that were granted to certain senior XTO employees will vest on the first anniversary of the effective date of the merger. Awards granted to certain former senior executives of XTO in connection with consulting agreements negotiated as part of the merger have vesting periods of one year for 50 percent of the award and of two or three years for the remaining 50 percent of the award, depending on the actual term of the consulting engagements.

The Corporation has purchased shares in the open market and through negotiated transactions to offset shares issued in conjunction with benefit plans and programs. Purchases may be discontinued at any time without prior notice.

In 2002, the Corporation began issuing restricted stock as stock-based compensation in lieu of stock options. Compensation expense for these awards is based on the price of the stock at the date of grant and has been recognized in income over the requisite service period. Prior to 2002, the Corporation issued stock options as stock-based compensation and since these awards vested prior to the effective date of current authoritative guidance, they continue to be accounted for under the prior prescribed method. 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 the stock and the exercise price of the options) on the date of grant. Since these two prices were the same on the date of grant, no compensation expense has been recognized in income for these awards.

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2010.

	2010	
Restricted stock and units outstanding	Shares	Weighted Average Grant-Date Fair Value per Share
	(thousands)	
Issued and outstanding at January 1	43,503	$67.52
2009 award issued in 2010	10,132	$75.40
Merger-related granted and converted XTO awards	4,206	$59.31
Vested	(10,377)	$61.72
Forfeited	(158)	$67.91
Issued and outstanding at December 31	47,306	$69.74

Value of restricted stock and units	2010	2009	2008
Grant price	$66.07	$75.40	$78.24
Value at date of grant:		*(millions of dollars)*	
Restricted stock and units settled in stock	$ 672	$ 711	$ 735
Merger-related granted and converted XTO awards	250	—	—
Units settled in cash	60	53	56
Total value	$ 982	$ 764	$ 791

As of December 31, 2010, there was $2,133 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.3 years. The compensation cost charged against income for the restricted stock and restricted units was $801 million, $723 million and $648 million for 2010, 2009 and 2008, respectively. The income tax benefit recognized in income related to this compensation expense was $81 million, $76 million and $75 million for the same periods, respectively. The fair value of shares and units vested in 2010, 2009 and 2008 was $718 million, $763 million and $438 million, respectively. Cash payments of $42 million, $41 million and $25 million for vested restricted stock units settled in cash were made in 2010, 2009 and 2008, respectively.

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Performance Stock. The Corporation granted 157 thousand of converted XTO performance stock awards with a grant-date fair value of $5 million as a result of the merger. Compensation cost for the performance stock awards is based on the estimated grant-date fair value. Vesting of XTO performance stock awards depended on the achievement of certain XTO stock thresholds. Upon conversion of these awards to ExxonMobil performance stock awards in connection with the merger, the performance thresholds were adjusted to equivalent market price thresholds for common stock of the Corporation. The performance stock awards are subject to forfeiture if the performance criteria are not met within the maximum term. Otherwise, holders of performance stock awards generally have all voting, dividend and other rights of other common stockholders.

The following table provides information about these converted performance stock awards as of December 31, 2010.

Performance stock awards	Dec. 31, 2010 Shares *(thousands)*
Vesting Price:	
$108.49	38
$119.76	38

During 2010, 80 thousand performance share awards vested.

Unrecognized compensation cost was $1 million at December 31, 2010. Compensation expense recognized in 2010 was $3 million.

Stock Options. The Corporation granted 12,393 thousand of converted XTO stock options with a grant-date fair value of $182 million as a result of the XTO merger. The grant included 893 thousand of unvested options. The converted XTO stock option awards are accounted for under current authoritative guidance, which requires the measurement and recognition of compensation expense based on estimated grant-date fair values. Upon conversion of these stock options to ExxonMobil stock options in connection with the merger, the performance thresholds were adjusted to equivalent market price thresholds for common stock of the Corporation. These stock options generally vest and become exercisable ratably over a three-year period, and may include a provision for accelerated vesting when the common stock price reaches specified levels. Some stock option tranches vest only when the common stock price reaches specified levels. As of December 31, 2010, unvested stock options of 574 thousand included 130 thousand options that vest ratably over three years and 444 thousand options that vest at stock prices ranging from $76.08 to $126.80.

Changes that occurred in the Corporation's stock options in 2010 are summarized below (shares in thousands):

	2010		
Stock options	Shares	Avg. Exercise Price	Weighted Average Remaining Contractual Term
Outstanding at January 1	41,473	$ 40.92	
Merger-related converted XTO awards	12,393	$ 55.15	
Exercised	(24,305)	$ 43.62	
Forfeited	(52)	$ 45.91	
Outstanding at December 31	29,509	$ 44.65	2.0 Years
Exercisable at December 31	28,935	$ 43.94	1.9 Years

Unrecognized compensation cost related to the nonvested merger-related converted XTO stock options was $1 million as of December 31, 2010. Compensation expense recognized in 2010 was $2 million. No compensation expense was recognized for stock options in 2009 and 2008, as all remaining outstanding stock options were granted prior to 2002 and were fully vested. Cash received from stock option exercises was $1,043 million, $752 million and $753 million for 2010, 2009 and 2008, respectively. The cash tax benefit realized for the options exercised was $89 million, $164 million and $273 million for 2010, 2009 and 2008, respectively. The aggregate intrinsic value of stock options exercised in 2010, 2009 and 2008 was $539 million, $563 million and $894 million, respectively. The intrinsic value for the balance of outstanding stock options at December 31, 2010, was $868 million. The intrinsic value for the balance of exercisable stock options at December 31, 2010, was $865 million.

Estimated Fair Value of XTO Merger-Related Grants. For restricted stock grants, the fair value was equal to the price of the common stock on the grant date. For the converted XTO stock options and performance stock, the Corporation used a Monte Carlo simulation model to estimate fair value. The Monte Carlo simulation model requires inputs for the risk-free interest rate, dividend yield, volatility, contract term, target vesting price, post-vesting turnover rate and sub-optimal exercise factor. Expected life, derived vesting period and fair value are outputs of this model.

The risk-free interest rate is based on the constant maturity nominal rates of U.S. Treasury securities with remaining lives throughout the contract term on the day of the grant. The dividend yield is the expected common stock annual dividend yield over the expected life of the option or performance stock, expressed as a percentage of the stock price on the date of grant. The volatility factors are based on a combination of both the historical volatilities of ExxonMobil's stock and the implied volatility of traded options on ExxonMobil common stock. Estimates of fair value are not intended to predict actual future events or the value ultimately realized by certain employees who receive stock option grants, and subsequent events are not indicative of the reasonableness of the original fair value estimates.

The total estimated fair value calculated at the time of the merger for the converted XTO stock-based awards was $352 million.

Fair values were determined using the following assumptions:

Weighted average expected term	2.5 years
Range of risk-free interest rates	0.1% - 2.6%
Weighted average risk-free interest rates	0.9%
Dividend yield	3.0%
Weighted average volatility	28.5%
Range of volatility	22.5% - 33.6%

15. 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. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. 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. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. 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, financial condition, or financial statements taken as a whole.

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Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2010, for $8,771 million, primarily relating to guarantees for notes, loans and performance under contracts. Included in this amount were guarantees by consolidated affiliates of $5,290 million, representing ExxonMobil's share of obligations of certain equity companies.

	Dec. 31, 2010		
	Equity Company Obligations	Other Third-Party Obligations	Total
		(millions of dollars)	
Guarantees	$ 5,290	$ 3,481	$8,771

Additionally, the Corporation and its affiliates 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 noncancelable 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			
	2011	2012-2015	2016 and Beyond	Total
		(millions of dollars)		
Unconditional purchase obligations [(1)]	$287	$748	$ 487	$1,522

(1) *Undiscounted obligations of $1,522 million mainly pertain to pipeline throughput agreements and include $996 million of obligations to equity companies. The present value of these commitments, which excludes imputed interest of $273 million, totaled $1,249 million.*

In accordance with a nationalization decree issued by Venezuela's president in February 2007, by May 1, 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. This Project had been operated and owned by ExxonMobil affiliates holding a 41.67 percent ownership interest in the Project. The decree also required conversion of the Cerro Negro Project into a "mixed enterprise" and an increase in PdVSA's or one of its affiliate's ownership interest in the Project, with the stipulation that if ExxonMobil refused to accept the terms for the formation of the mixed enterprise within a specified period of time, the government would "directly assume the activities" carried out by the joint venture. ExxonMobil refused to accede to the terms proffered by the government, and on June 27, 2007, the government expropriated ExxonMobil's 41.67 percent interest in the Cerro Negro Project.

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID) invoking ICSID jurisdiction under Venezuela's Investment Law and the Netherlands-Venezuela Bilateral Investment Treaty. The ICSID Tribunal issued a decision on June 10, 2010, finding that it had jurisdiction to proceed on the basis of the Netherlands-Venezuela Bilateral Investment Treaty. The ICSID arbitration proceeding is continuing and a hearing on the merits is currently scheduled for the first quarter of 2012. An affiliate of ExxonMobil has also filed an arbitration under the rules of the International Chamber of Commerce (ICC) against PdVSA and a PdVSA affiliate for breach of their contractual obligations under certain Cerro Negro Project agreements. A hearing on the merits of the ICC arbitration concluded in September 2010 and the parties filed post-hearing briefs. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition. ExxonMobil's remaining net book investment in Cerro Negro producing assets is about $750 million.

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16. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2010	2009	2010	2009	2010	2009
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	5.50	6.00	4.80	5.20	5.50	6.00
Long-term rate of compensation increase	5.00	5.00	5.20	5.00	5.00	5.00
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	$13,981	$13,272	$23,344	$19,990	$6,748	$ 6,633
Service cost	468	438	480	421	101	94
Interest cost	798	809	1,175	1,121	395	408
Actuarial loss/(gain)	553	1,126	1,672	1,280	277	(49)
Benefits paid (1) (2)	(873)	(1,665)	(1,281)	(1,174)	(394)	(480)
Foreign exchange rate changes	—	—	169	1,676	26	60
Plan amendments, other	80	1	163	30	178	82
Benefit obligation at December 31	$15,007	$13,981	$25,722	$23,344	$7,331	$ 6,748
Accumulated benefit obligation at December 31	$12,764	$11,615	$22,958	$20,909	$ —	$ —

(1) Benefit payments for funded and unfunded plans.
(2) For 2010 and 2009, other postretirement benefits paid are net of $15 million and $28 million of Medicare subsidy receipts, respectively.

For U.S. plans, the discount rate is determined by constructing a portfolio of high-quality, noncallable 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 an initial health care cost trend rate of 6.0 percent that declines to 4.5 percent by 2015. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $57 million and the postretirement benefit obligation by $599 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $45 million and the post-retirement benefit obligation by $494 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2010	2009	2010	2009	2010	2009
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	$10,277	$ 6,634	$15,401	$11,260	$ 514	$ 443
Actual return on plan assets	1,235	2,013	1,482	2,201	63	93
Foreign exchange rate changes	—	—	99	1,300	—	—
Company contribution	—	3,070	1,184	1,456	38	36
Benefits paid (1)	(677)	(1,440)	(873)	(795)	(59)	(57)
Other	—	—	(528)	(21)	2	(1)
Fair value at December 31	$10,835	$10,277	$16,765	$15,401	$ 558	$ 514

(1) Benefit payments for funded plans.

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The funding levels of all qualified pension plans are in compliance with standards set by applicable law or regulation. As shown in the table below, certain smaller U.S. pension plans and a number of non-U.S. pension 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.

	Pension Benefits			
	U.S.		Non-U.S.	
	2010	2009	2010	2009
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	$(2,349)	$(1,940)	$(2,769)	$(2,085)
Unfunded plans	(1,823)	(1,764)	(6,188)	(5,858)
Total	$(4,172)	$(3,704)	$(8,957)	$(7,943)

The authoritative guidance for defined benefit pension and other post-retirement plans requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2010	2009	2010	2009	2010	2009
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	$(4,172)	$(3,704)	$(8,957)	$(7,943)	$(6,773)	$(6,234)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	$ 1	$ 1	$ 400	$ 961	$ —	$ —
Current liabilities	(257)	(235)	(336)	(348)	(343)	(318)
Postretirement benefits reserves	(3,916)	(3,470)	(9,021)	(8,556)	(6,430)	(5,916)
Total recorded	$(4,172)	$(3,704)	$(8,957)	$(7,943)	$(6,773)	$(6,234)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	$ 5,028	$ 5,830	$ 7,795	$ 7,036	$ 1,985	$ 1,878
Prior service cost	83	5	674	622	154	181
Total recorded in accumulated other comprehensive income	$ 5,111	$ 5,835	$ 8,469	$ 7,658	$ 2,139	$ 2,059

(1) Fair value of assets less benefit obligation shown on the preceding page.

The long-term expected rate of return on funded assets shown below is established for each benefit 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.

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2010	2009	2008	2010	2009	2008	2010	2009	2008
					(percent)				
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31									
Discount rate	6.00	6.25	6.25	5.20	5.50	5.40	6.00	6.25	6.25
Long-term rate of return on funded assets	7.50	8.00	9.00	6.70	7.30	7.50	7.50	8.00	9.00
Long-term rate of compensation increase	5.00	5.00	5.00	5.00	4.70	4.50	5.00	5.00	5.00
					(millions of dollars)				
Components of net periodic benefit cost									
Service cost	$ 468	$ 438	$ 378	$ 480	$ 421	$ 434	$ 101	$ 94	$ 100
Interest cost	798	809	729	1,175	1,121	1,152	395	408	414
Expected return on plan assets	(726)	(656)	(915)	(1,010)	(886)	(1,200)	(37)	(35)	(59)
Amortization of actuarial loss/(gain)	525	694	239	554	648	318	147	176	197
Amortization of prior service cost	2	—	(2)	84	79	93	52	69	76
Net pension enhancement and curtailment/settlement expense	321	485	174	9	2	32	—	—	—
Net periodic benefit cost	$1,388	$ 1,770	$ 603	$ 1,292	$1,385	$ 829	$ 658	$ 712	$ 728
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	$ 44	$ (231)	$5,275	$ 1,202	$ (33)	$ 4,837	$ 251	$(107)	$ 13
Amortization of actuarial (loss)/gain	(846)	(1,179)	(413)	(563)	(650)	(350)	(147)	(176)	(197)
Prior service cost/(credit)	80	—	—	160	69	16	26	—	—
Amortization of prior service (cost)	(2)	—	2	(84)	(79)	(93)	(52)	(69)	(76)
Foreign exchange rate changes	—	—	—	96	608	(997)	2	2	(3)
Total recorded in other comprehensive income	(724)	(1,410)	4,864	811	(85)	3,413	80	(350)	(263)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	$ 664	$ 360	$5,467	$ 2,103	$1,300	$ 4,242	$ 738	$ 362	$ 465

Costs for defined contribution plans were $347 million, $339 million and $309 million in 2010, 2009 and 2008, respectively.

A summary of the change in accumulated other comprehensive income is shown in the table below:

	Total Pension and Other Postretirement Benefits		
	2010	2009	2008
		(millions of dollars)	
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	$ 724	$ 1,410	$ (4,864)
Non-U.S. pension	(811)	85	(3,413)
Other postretirement benefits	(80)	350	263
Total (charge)/credit to other comprehensive income, before tax	(167)	1,845	(8,014)
(Charge)/credit to income tax (see note 18)	35	(591)	2,723
(Charge)/credit to investment in equity companies	11	(133)	(27)
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	$ (121)	$ 1,121	$ (5,318)
Charge/(credit) to equity of noncontrolling interests	95	93	224
(Charge)/credit to other comprehensive income attributable to ExxonMobil	$ (26)	$ 1,214	$ (5,094)

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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 benefit plan assets are primarily invested in passive equity and fixed income index funds to diversify risk while minimizing costs. The equity funds hold ExxonMobil stock only to the extent necessary to replicate the relevant equity index. The fixed income funds are largely invested in high-quality corporate and government debt securities.

Studies are periodically conducted to establish the preferred target asset allocation. The target asset allocation for the U.S. benefit plans is 60% equity securities and 40% debt securities. The target asset allocation for the non-U.S. plans in aggregate is 56% equities, 41% debt and 3% real estate funds. The equity targets for the U.S. and non-U.S. plans include an allocation to private equity partnerships that primarily focus on early-stage venture capital of 5% and 3%, respectively.

The fair value measurement levels are accounting terms that refer to different methods of valuing assets. The terms do not represent the relative risk or credit quality of an investment.

The 2010 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension				Non-U.S. Pension			
	Fair Value Measurement at December 31, 2010, Using:				Fair Value Measurement at December 31, 2010, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(millions of dollars)				*(millions of dollars)*			
Asset category:								
Equity securities								
U.S.	$ —	$ 2,648[(1)]	$ —	$ 2,648	$ —	$ 2,443[(1)]	$ —	$ 2,443
Non-U.S.	—	3,530[(1)]	—	3,530	228[(2)]	6,502[(1)]	—	6,730
Private equity	—	—	408[(3)]	408	—	—	315[(3)]	315
Debt securities								
Corporate	—	1,152[(4)]	—	1,152	2[(5)]	1,629[(4)]	—	1,631
Government	—	2,847[(4)]	—	2,847	146[(5)]	4,709[(4)]	—	4,855
Asset-backed	—	31[(4)]	—	31	—	98[(4)]	—	98
Private mortgages	—	—	128[(6)]	128	—	—	4[(6)]	4
Real estate funds	—	—	—	—	—	—	417[(7)]	417
Cash	68	—	—	68	63	51[(8)]	—	114
Total at fair value	$ 68	$ 10,208	$ 536	$10,812	$ 439	$ 15,432	$ 736	$16,607
Insurance contracts at contract value				23				158
Total plan assets				$10,835				$16,765

(1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(2) For non-U.S. equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

(3) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(4) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

(5) For corporate and government debt securities that are traded on active exchanges, fair value is based on observable quoted prices.

(6) For private mortgages, fair value is based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

(7) For real estate funds, fair value is based on appraised values developed using comparable market transactions.

(8) For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a Level 2 input.

	Other Postretirement			
	Fair Value Measurement at December 31, 2010, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	$ —	$ 180[(1)]	$ —	$180
Non-U.S.	—	191[(1)]	—	191
Private equity	—	—	5[(2)]	5
Debt securities				
Corporate	—	49[(3)]	—	49
Government	—	117[(3)]	—	117
Asset-backed	—	13[(3)]	—	13
Private mortgages	—	—	2[(4)]	2
Cash	1	—	—	1
Total at fair value	$ 1	$ 550	$ 7	$558

(1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(2) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(3) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

(4) For private mortgages, fair value is based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

The change in the fair value in 2010 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2010						
	Pension					Other Postretirement	
	U.S.		Non U.S.				
	Private Equity	Private Mortgages	Private Equity	Private Mortgages	Real Estate	Private Equity	Private Mortgages
	(millions of dollars)						
Fair value at January 1	$ 349	$ 280	$ 239	$ 5	$413	$ 4	$ 3
Net realized gains/(losses)	—	36	(1)	(1)	—	—	1
Net unrealized gains/(losses)	47	(3)	26	1	(4)	1	—
Net purchases/(sales)	12	(185)	51	(1)	8	—	(2)
Fair value at December 31	$ 408	$ 128	$ 315	$ 4	$417	$ 5	$ 2

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The 2009 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension				Non-U.S. Pension			
	Fair Value Measurement at December 31, 2009, Using:				Fair Value Measurement at December 31, 2009, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(millions of dollars)				*(millions of dollars)*		
Asset category:								
Equity securities								
U.S.	$ —	$ 2,503[1]	$ —	$ 2,503	$ —	$ 2,244[1]	$ —	$ 2,244
Non-U.S.	—	3,341[1]	—	3,341	227[2]	5,946[1]	—	6,173
Private equity	—	—	349[3]	349	—	—	239[3]	239
Debt securities								
Corporate	—	1,040[4]	—	1,040	2[5]	1,637[4]	—	1,639
Government	—	2,570[4]	—	2,570	70[5]	4,217[4]	—	4,287
Asset-backed	—	30[4]	—	30	—	119[4]	—	119
Private mortgages	—	—	280[6]	280	—	—	5[6]	5
Real estate funds	—	—	—	—	—	—	413[7]	413
Cash	140	—	—	140	79	55[8]	—	134
Total at fair value	$ 140	$ 9,484	$ 629	$10,253	$ 378	$ 14,218	$ 657	$15,253
Insurance contracts at contract value				24				148
Total plan assets				$10,277				$15,401

(1) *For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.*

(2) *For non-U.S. equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.*

(3) *For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.*

(4) *For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.*

(5) *For corporate and government debt securities that are traded on active exchanges, fair value is based on observable quoted prices.*

(6) *For private mortgages, fair value is based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.*

(7) *For real estate funds, fair value is based on appraised values developed using comparable market transactions.*

(8) *For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a Level 2 input.*

	Other Postretirement			
	Fair Value Measurement at December 31, 2009, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	$ —	$ 166(1)	$ —	$166
Non-U.S.	—	181(1)	—	181
Private equity	—	—	4(2)	4
Debt securities				
Corporate	—	51(3)	—	51
Government	—	95(3)	—	95
Asset-backed	—	11(3)	—	11
Private mortgages	—	—	3(4)	3
Cash	3	—	—	3
Total at fair value	$ 3	$ 504	$ 7	$514

(1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are Level 1 inputs.

(2) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Initial Public Offerings.

(3) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transactions.

(4) For private mortgages, fair value is based on proprietary credit spread matrices developed using market data and monthly surveys of active mortgage bankers.

The change in the fair value in 2009 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2009						
	Pension					Other Postretirement	
	U.S.		Non U.S.				
	Private Equity	Private Mortgages	Private Equity	Private Mortgages	Real Estate	Private Equity	Private Mortgages
	(millions of dollars)						
Fair value at January 1	$ 346	$ 476	$ 238	$ 5	$409	$ 4	$ 6
Net realized gains/(losses)	4	11	(10)	—	(7)	—	—
Net unrealized gains/(losses)	(35)	7	(35)	—	(11)	—	—
Net purchases/(sales)	34	(214)	46	—	22	—	(3)
Fair value at December 31	$ 349	$ 280	$ 239	$ 5	$413	$ 4	$ 3

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2010	2009	2010	2009
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	$13,184	$12,217	$ 9,865	$ 13,152
Accumulated benefit obligation	11,383	10,312	9,074	12,260
Fair value of plan assets	10,834	10,276	7,131	10,447
For unfunded pension plans:				
Projected benefit obligation	$ 1,823	$ 1,764	$ 6,188	$ 5,858
Accumulated benefit obligation	1,381	1,303	5,413	5,180

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2011 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) (1)	$ 835	$ 615	$ 159
Prior service cost (2)	9	97	35

(1) *The Corporation amortizes the net balance of actuarial losses/(gains) as a component of net periodic benefit cost over the average remaining service period of active plan participants.*

(2) *The Corporation amortizes prior service cost on a straight-line basis as permitted under authoritative guidance for defined benefit pension and other postretirement benefit plans.*

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2011	$ 270	$ 1,130	$ —	$ —
Benefit payments expected in:				
2011	1,454	1,299	440	23
2012	1,483	1,281	456	25
2013	1,512	1,316	474	26
2014	1,451	1,362	489	28
2015	1,392	1,393	502	29
2016 - 2020	6,079	8,325	2,662	163

17. 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 (1) that engage in business activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Corporation's chief operating decision maker to make decisions about resources to be allocated to the segment and assess its performance; and (3) for which discrete financial information is available.

Earnings after income tax include special items, and transfers are at estimated market prices. Earnings for 2009 included a special charge of $140 million in the corporate and financing segment for interest related to the Valdez punitive damages award. Special items included in 2008 after-tax earnings were a $1,620 million gain in Non-U.S. Upstream on the sale of a natural gas transportation business in Germany and special charges of $460 million in the corporate and financing segment related to the Valdez litigation.

Interest expense includes non-debt-related interest expense of $41 million, $500 million and $498 million in 2010, 2009 and 2008, respectively. Higher expenses in 2009 and 2008 primarily reflect interest provisions related to the Valdez litigation.

In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities.

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	Upstream		Downstream		Chemical		Corporate and	Corporate
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	Financing	Total
				(millions of dollars)				
As of December 31, 2010								
Earnings after income tax	$ 4,272	$ 19,825	$ 770	$ 2,797	$ 2,422	$ 2,491	$ (2,117)	$ 30,460
Earnings of equity companies included above	1,261	8,415	23	225	171	1,163	(581)	10,677
Sales and other operating revenue *(1)*	8,895	26,046	93,599	206,042	13,402	22,119	22	370,125
Intersegment revenue	8,102	39,066	13,546	52,697	9,694	8,421	282	—
Depreciation and depletion expense	3,506	7,574	681	1,565	421	432	581	14,760
Interest revenue	—	—	—	—	—	—	118	118
Interest expense	20	25	1	19	1	4	189	259
Income taxes	2,219	18,627	360	560	736	347	(1,288)	21,561
Additions to property, plant and equipment	52,300	16,937	888	1,332	247	1,733	719	74,156
Investments in equity companies	2,636	9,625	254	1,240	285	3,586	(197)	17,429
Total assets	76,725	115,646	18,378	47,402	7,148	19,087	18,124	302,510
As of December 31, 2009								
Earnings after income tax	$ 2,893	$ 14,214	$ (153)	$ 1,934	$ 769	$ 1,540	$ (1,917)	$ 19,280
Earnings of equity companies included above	1,216	5,269	(102)	188	164	906	(498)	7,143
Sales and other operating revenue *(1)*	3,406	21,355	76,467	173,404	9,962	16,885	21	301,500
Intersegment revenue	6,718	32,982	10,168	39,190	7,185	6,947	284	—
Depreciation and depletion expense	1,768	6,376	687	1,665	400	457	564	11,917
Interest revenue	—	—	—	—	—	—	179	179
Interest expense	38	27	10	18	4	1	450	548
Income taxes	1,451	15,183	(164)	(22)	281	(182)	(1,428)	15,119
Additions to property, plant and equipment	2,973	13,307	1,449	1,447	294	2,553	468	22,491
Investments in equity companies	2,440	8,864	323	1,190	259	2,873	(207)	15,742
Total assets	24,940	102,372	17,493	45,098	7,044	17,117	19,259	233,323
As of December 31, 2008								
Earnings after income tax	$ 6,243	$ 29,159	$ 1,649	$ 6,502	$ 724	$ 2,233	$ (1,290)	$ 45,220
Earnings of equity companies included above	1,954	7,597	(2)	518	105	1,411	(502)	11,081
Sales and other operating revenue *(1)*	6,767	32,346	116,701	265,359	14,136	24,252	18	459,579
Intersegment revenue	9,617	55,069	16,225	65,723	9,925	9,749	273	—
Depreciation and depletion expense	1,391	7,266	656	1,672	410	422	562	12,379
Interest revenue	—	—	—	—	—	—	1,400	1,400
Interest expense	47	63	9	28	3	4	519	673
Income taxes	3,451	30,654	728	1,990	177	10	(480)	36,530
Additions to property, plant and equipment	2,699	10,545	1,550	1,552	413	1,987	572	19,318
Investments in equity companies	2,248	7,787	456	1,382	241	2,384	(40)	14,458
Total assets	23,056	83,750	16,328	42,044	6,856	13,300	42,718	228,052

Geographic

Sales and other operating revenue *(1)*	2010	2009	2008
		(millions of dollars)	
United States	$115,906	$ 89,847	$137,615
Non-U.S.	254,219	211,653	321,964
Total	$370,125	$301,500	$459,579
Significant non-U.S. revenue sources include:			
Canada	$ 27,243	$ 21,151	$ 33,677
Japan	27,143	22,054	30,126
United Kingdom	24,637	20,293	29,764
Belgium	21,139	16,857	25,399
Germany	14,301	14,839	20,591
Italy	14,132	12,997	17,953
France	13,920	12,042	18,530
Singapore	11,088	8,400	11,059

Long-lived assets	2010	2009	2008
		(millions of dollars)	
United States	$ 86,021	$ 37,138	$ 35,548
Non-U.S.	113,527	101,978	85,798
Total	$199,548	$139,116	$121,346
Significant non-U.S. long-lived assets include:			
Canada	$ 20,879	$ 15,919	$ 12,018
Nigeria	11,429	11,046	9,227
Singapore	8,610	7,238	5,113
Angola	8,570	7,320	6,129
Norway	6,988	7,251	5,856

Australia	6,570	4,247	2,857
United Kingdom	6,177	7,609	5,778
Kazakhstan	5,938	4,748	3,535

(1) *Sales and other operating revenue includes sales-based taxes of $28,547 million for 2010, $25,936 million for 2009 and $34,508 million for 2008. See note 1, Summary of Accounting Policies.*

18. Income, Sales-Based and Other Taxes

	2010 U.S.	2010 Non-U.S.	2010 Total	2009 U.S.	2009 Non-U.S.	2009 Total	2008 U.S.	2008 Non-U.S.	2008 Total
					(millions of dollars)				
Income taxes									
Federal and non-U.S.									
Current	$1,224	$21,093	$22,317	$ (838)	$15,830	$14,992	$ 3,005	$ 31,377	$ 34,382
Deferred – net	49	(1,191)	(1,142)	650	(665)	(15)	168	1,289	1,457
U.S. tax on non-U.S. operations	46	—	46	32	—	32	230	—	230
Total federal and non-U.S.	1,319	19,902	21,221	(156)	15,165	15,009	3,403	32,666	36,069
State	340	—	340	110	—	110	461	—	461
Total income taxes	1,659	19,902	21,561	(46)	15,165	15,119	3,864	32,666	36,530
Sales-based taxes	6,182	22,365	28,547	6,271	19,665	25,936	6,646	27,862	34,508
All other taxes and duties									
Other taxes and duties	776	35,342	36,118	581	34,238	34,819	1,663	40,056	41,719
Included in production and manufacturing expenses	1,001	1,237	2,238	699	1,318	2,017	915	1,720	2,635
Included in SG&A expenses	201	570	771	197	538	735	209	660	869
Total other taxes and duties	1,978	37,149	39,127	1,477	36,094	37,571	2,787	42,436	45,223
Total	$9,819	$79,416	$89,235	$7,702	$70,924	$78,626	$13,297	$102,964	$116,261

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 a net charge of $175 million in 2010 and net credits of $9 million in 2009 and $300 million in 2008 for the effect of changes in tax laws and rates.

Income taxes (charged)/credited directly to equity were:

	2010	2009	2008
		(millions of dollars)	
Cumulative foreign exchange translation adjustment	$ (42)	$(247)	$ 360
Postretirement benefits reserves adjustment:			
Net actuarial loss/(gain)	553	(94)	3,361
Amortization of actuarial loss/(gain)	(609)	(649)	(317)
Prior service cost	92	20	4
Amortization of prior service cost	(45)	(43)	(51)
Foreign exchange rate changes	44	175	(274)
Total postretirement benefits reserves adjustment	35	(591)	2,723
Other components of equity	246	140	315

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2010, 2009 and 2008 is as follows:

	2010	2009	2008
		(millions of dollars)	
Income before income taxes			
United States	$ 7,711	$ 2,576	$10,152
Non-U.S.	45,248	32,201	73,245
Total	$52,959	$34,777	$83,397
Theoretical tax	$18,536	$12,172	$29,189
Effect of equity method of accounting	(3,737)	(2,500)	(3,878)
Non-U.S. taxes in excess of theoretical U.S. tax	7,293	5,948	10,188
U.S. tax on non-U.S. operations	46	32	230
State taxes, net of federal tax benefit	221	72	300
Other U.S.	(798)	(605)	501
Total income tax expense	$21,561	$15,119	$36,530
Effective tax rate calculation			
Income taxes	$21,561	$15,119	$36,530
ExxonMobil share of equity company income taxes	4,058	2,489	4,001
Total income taxes	25,619	17,608	40,531
Net income including noncontrolling interests	31,398	19,658	46,867
Total income before taxes	$57,017	$37,266	$87,398
Effective income tax rate	45%	47%	46%

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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:	2010	2009
	(millions of dollars)	
Property, plant and equipment	$ 42,657	$ 29,931
Other liabilities	4,278	4,102
Total deferred tax liabilities	$ 46,935	$ 34,033
Pension and other postretirement benefits	$ (5,634)	$ (5,442)
Asset retirement obligations	(4,461)	(3,978)
Tax loss carryforwards	(3,243)	(3,693)
Other assets	(6,070)	(4,700)
Total deferred tax assets	$(19,408)	$(17,813)
Asset valuation allowances	1,183	1,495
Net deferred tax liabilities	$ 28,710	$ 17,715

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	2010	2009
	(millions of dollars)	
Other current assets	$ (3,359)	$ (3,322)
Other assets, including intangibles, net	(3,527)	(2,263)
Accounts payable and accrued liabilities	446	152
Deferred income tax liabilities	35,150	23,148
Net deferred tax liabilities	$28,710	$17,715

The Corporation had $35 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.

Unrecognized Tax Benefits

The Corporation is subject to income taxation in many jurisdictions around the world. Unrecognized tax benefits reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the financial statements. Resolution of the related tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control of the Corporation. It is reasonably possible that the total amount of unrecognized tax benefits could increase by up to 20 percent or decrease by up to 5 percent in the next 12 months. Given the long time periods involved in resolving tax positions, the Corporation does not expect that the recognition of unrecognized tax benefits will have a material impact on the Corporation's effective income tax rate in any given year.

The following table summarizes the movement in unrecognized tax benefits.

Gross unrecognized tax benefits	2010	2009	2008
		(millions of dollars)	
Balance at January 1	$4,725	$4,976	$5,232
Additions based on current year's tax positions	830	547	656
Additions for prior years' tax positions	620	262	294
Reductions for prior years' tax positions	(505)	(594)	(328)
Reductions due to lapse of the statute of limitations	(534)	—	(27)
Settlements with tax authorities	(999)	(592)	(681)
Foreign exchange effects/other	11	126	(170)
Balance at December 31	$4,148	$4,725	$4,976

The additions and reductions in unrecognized tax benefits shown above include effects related to net income and equity, and timing differences for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. The 2010, 2009 and 2008 changes in unrecognized tax benefits did not have a material effect on the Corporation's net income or cash flow.

The following table summarizes the tax years that remain subject to examination by major tax jurisdiction:

Country of Operation	Open Tax Years
Abu Dhabi	2000 -2010
Angola	2007 -2010
Australia	2000 -2010
Canada	1994 -2010
Equatorial Guinea	2005 -2010
Germany	1999 -2010
Japan	2003 -2010
Malaysia	2004 -2010

Nigeria	1998 -2010
Norway	2000 -2010
United Kingdom	2004 -2010
United States:	1991 -1996
	1998 -2000
	2004 -2010

The Corporation classifies interest on income tax-related balances as interest expense or interest income and classifies tax-related penalties as operating expense.

In 2010, the Corporation’s resolution of certain tax positions with tax jurisdictions resulted in a decrease in the total amount of unrecognized tax benefits and the related interest payable. For 2010, net interest expense was a credit of $39 million, reflecting the effect of credits from the net favorable resolution of these prior year tax positions. The Corporation incurred approximately $135 million and $137 million in interest expense on income tax reserves in 2009 and 2008, respectively. The related interest payable balances were $636 million and $771 million at December 31, 2010, and 2009, respectively.

19. Acquisition of XTO Energy Inc.

Description of the Transaction. On June 25, 2010, ExxonMobil acquired XTO Energy Inc. (XTO) by merging a wholly-owned subsidiary of ExxonMobil with and into XTO (the “merger”), with XTO continuing as the surviving corporation and wholly-owned subsidiary of ExxonMobil. XTO is involved in the exploration for, production of, and transportation and sale of crude oil and natural gas. XTO’s asset base, technical capabilities and operating expertise, together with ExxonMobil’s extensive research and development expertise, project management and operational skills, global scale and financial capacity, should enable effective development of additional supplies of unconventional oil and gas resources.

At the effective time of the merger, each share of XTO common stock was converted into the right to receive 0.7098 shares of common stock of ExxonMobil (the “Exchange Ratio”), with cash being paid in lieu of any fractional shares of ExxonMobil stock. Also at the effective time, each outstanding option to purchase XTO common stock was converted into an option to purchase a number of shares of ExxonMobil stock based on the Exchange Ratio, and each outstanding restricted stock award and performance stock award of XTO was converted into a restricted stock award or performance stock award, as applicable, of ExxonMobil stock based on the Exchange Ratio.

The components of the consideration transferred follow:

		(millions of dollars)
Consideration attributable to stock issued (1) (2)	$	24,480
Consideration attributable to converted stock options (2)		179
Total consideration transferred	$	24,659

(1) The fair value of the Corporation’s common stock on the acquisition date was $59.10 per share based on the closing value on the NYSE. The Corporation issued 416 million shares of stock previously held in treasury. The treasury stock issued, based on the average cost, was valued at $21,139 million. The excess of the fair value of the consideration transferred over the cost of treasury stock issued was $3,520 million and was included in common stock without par value.

(2) The portion of the fair value of XTO converted stock-based awards attributable to pre-merger employee service was part of consideration. The remaining fair value of the awards will be recognized in future periods over the requisite service period.

Recording of Assets Acquired and Liabilities Assumed. The transaction was accounted for using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date.

The following table summarizes the assets acquired and liabilities assumed:

		(millions of dollars)
Cash and cash equivalents	$	47
Notes and accounts receivable		925
Inventories		170
Other current assets (1)		911
Investments, advances and long-term receivables		52
Property, plant and equipment (2)		47,300
Identifiable intangible assets (3)		493
Goodwill (4)		39
Other assets (1)		75
Total assets acquired	$	50,012
Notes and loans payable (5)	$	1,026
Accounts payable and accrued liabilities (1) (6)		1,788
Income taxes payable		(199)
Long-term debt (5)		10,574
Postretirement benefits reserves		65
Deferred income tax liabilities (6)		11,204
Other long-term obligations		895
Total liabilities assumed	$	25,353
Net assets acquired	$	24,659

(1) Derivatives were measured using Level 1 inputs for derivatives that are traded directly on the NYMEX and Level 2 inputs for derivatives that are determined by either market prices on an active market for similar assets or by prices quoted by a broker or other market-corroborated prices.

(2) Property, plant and equipment were measured primarily using an income approach. The fair value measurements of the oil and gas assets were based, in part, on significant inputs not observable in the market and thus represent a Level 3 measurement. The significant inputs included XTO resources, assumed future production profiles, commodity prices (mainly based on observable market inputs), risk adjusted discount rate of 7.0 percent, inflation of 2.0 percent and assumptions on the timing and amount of future development and operating costs. The property, plant and equipment additions were segmented to the Upstream business, with substantially all of the assets in the United States.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(3) Identifiable intangible assets and other assets were measured using a combination of an income approach and a market approach (Level 3). Identifiable intangible assets will be amortized over 20 years.
(4) Goodwill was the excess of the consideration transferred over the net assets recognized and represents the future economic benefits arising from other assets acquired that could not be individually identified and separately recognized. Goodwill was recognized in the Upstream reporting unit. Goodwill is not amortized and is not deductible for tax purposes.
(5) Long-term debt was recognized mainly at market rates at closing (Level 1).
(6) Deferred income taxes reflect the temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

XTO Results and Pro Forma Impact of Merger. The following table presents revenues and earnings for XTO for the periods presented:

	Acquisition Date Through December 31, 2010
	(millions of dollars)
Revenues	$ 4,448
Upstream earnings	$ 262

Transaction-related costs were expensed as incurred. The Corporation recognized $18 million in transaction costs related to the merger in 2010.

The following table presents unaudited pro forma information for the Corporation as if the merger of XTO had occurred at the beginning of each year presented:

	2010	2009
	(millions of dollars, except per share amounts)	
Revenues	$ 373,273	$ 307,456
Net income attributable to ExxonMobil	$ 30,668	$ 19,672
Earnings per common share	$ 6.03	$ 3.75
Earnings per common share – assuming dilution	$ 6.01	$ 3.74

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the merger and factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the consolidated results of operations actually would have been had the merger been completed on January 1, 2010, or on January 1, 2009. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations of the combined company. The unaudited pro forma consolidated results reflect pro forma adjustments for the elimination of deferred gains and losses recognized in earnings for derivatives outstanding at the beginning of the year presented, depreciation expense related to the fair value adjustment to property, plant and equipment acquired, additional amortization expense related to the fair value of identifiable intangible assets acquired, capitalization of interest expense and applicable income tax impacts.

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $249 million in 2010, $536 million in 2009, and $3,834 million in 2008. Oil sands mining operations were in the excluded amounts for 2008. However, beginning in 2009, oil sands mining operations are included in the results of operations in accordance with revised Securities and Exchange Commission and Financial Accounting Standards Board rules. The amounts included for oil sands mining operations in the results of operations for 2009 are shown in footnote 1 on page 104.

Results of Operations – Consolidated Subsidiaries	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
2010 – Revenue							
Sales to third parties	$ 5,334	$ 1,218	$ 6,055	$ 4,227	$ 4,578	$ 696	$22,108
Transfers	7,070	5,832	7,120	13,295	6,031	1,123	40,471
	$ 12,404	$ 7,050	$13,175	$17,522	$10,609	$ 1,819	$62,579
Production costs excluding taxes	2,794	2,612	2,717	2,215	1,308	462	12,108
Exploration expenses	283	464	394	587	360	56	2,144
Depreciation and depletion	3,350	1,015	2,531	2,580	1,141	219	10,836
Taxes other than income	1,188	86	482	1,742	1,298	204	5,000
Related income tax	2,093	715	4,728	6,068	3,852	262	17,718
Results of producing activities for consolidated subsidiaries	$ 2,696	$ 2,158	$ 2,323	$ 4,330	$ 2,650	$ 616	$14,773

Results of Operations – Equity Companies	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
2010 – Revenue							
Sales to third parties	$ 1,012	$ —	$ 5,050	$ —	$12,682	$ —	$18,744
Transfers	867	—	68	—	3,817	—	4,752
	$ 1,879	$ —	$ 5,118	$ —	$16,499	$ —	$23,496
Production costs excluding taxes	481	—	294	—	320	—	1,095
Exploration expenses	4	—	19	—	2	—	25
Depreciation and depletion	157	—	188	—	455	—	800
Taxes other than income	32	—	2,515	—	3,844	—	6,391
Related income tax	—	—	815	—	5,295	—	6,110
Results of producing activities for equity companies	$ 1,205	$ —	$ 1,287	$ —	$ 6,583	$ —	$ 9,075
Total results of operations	$ 3,901	$ 2,158	$ 3,610	$ 4,330	$ 9,233	$ 616	$23,848

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

Results of Operations – Consolidated Subsidiaries		United States	Canada/ South America(1)	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)				
2009 –	Revenue							
	Sales to third parties	$ 1,859	$ 1,345	$ 5,900	$ 3,012	$ 2,637	$ 586	$15,339
	Transfers	5,652	4,538	5,977	11,868	5,433	1,066	34,534
		$ 7,511	$ 5,883	$11,877	$14,880	$ 8,070	$ 1,652	$49,873
	Production costs excluding taxes	2,255	2,428	2,675	2,027	1,247	386	11,018
	Exploration expenses	219	339	375	662	393	33	2,021
	Depreciation and depletion	1,670	948	2,078	2,293	816	195	8,000
	Taxes other than income	730	78	593	1,343	991	252	3,987
	Related income tax	1,127	597	4,277	4,667	2,822	237	13,727
	Results of producing activities for consolidated subsidiaries	$ 1,510	$ 1,493	$ 1,879	$ 3,888	$ 1,801	$ 549	$11,120
Results of Operations – Equity Companies								
2009 –	Revenue							
	Sales to third parties	$ 818	$ —	$ 4,889	$ —	$ 6,148	$ —	$11,855
	Transfers	686	—	53	—	2,960	—	3,699
		$ 1,504	$ —	$ 4,942	$ —	$ 9,108	$ —	$15,554
	Production costs excluding taxes	481	—	248	—	251	—	980
	Exploration expenses	1	—	12	—	—	—	13
	Depreciation and depletion	163	—	168	—	366	—	697
	Taxes other than income	37	—	2,233	—	2,120	—	4,390
	Related income tax	—	—	902	—	3,121	—	4,023
	Results of producing activities for equity companies	$ 822	$ —	$ 1,379	$ —	$ 3,250	$ —	$ 5,451
Total results of operations		$ 2,332	$ 1,493	$ 3,258	$ 3,888	$ 5,051	$ 549	$16,571
Results of Operations								
2008 –	Revenue							
	Sales to third parties	$ 3,980	$ 4,591	$11,239	$ 2,284	$ 4,294	$ 808	$27,196
	Transfers	8,525	3,518	10,859	18,361	9,417	1,692	52,372
		$ 12,505	$ 8,109	$22,098	$20,645	$13,711	$ 2,500	$79,568
	Production costs excluding taxes	2,143	1,686	2,623	1,603	1,100	332	9,487
	Exploration expenses	189	232	180	439	292	109	1,441
	Depreciation and depletion	1,303	906	2,510	2,471	965	179	8,334
	Taxes other than income	1,983	58	971	1,815	2,333	665	7,825
	Related income tax	3,191	1,501	10,715	8,119	5,357	399	29,282
	Results of producing activities for consolidated subsidiaries	$ 3,696	$ 3,726	$ 5,099	$ 6,198	$ 3,664	$ 816	$23,199
	Proportional interest in results of producing activities of equity companies	$ 1,885	$ —	$ 1,918	$ —	$ 4,566	$ —	$ 8,369

(1) *The impact of including synthetic oil reserves and bitumen mining operations in the results of operations for 2009 was $1,447 million in revenue and $279 million in earnings. Cold Lake bitumen operations had no net impact as they had already been included in the results of operations in previous years as an oil and gas operation.*

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $4,729 million less at year-end 2010 and $2,910 million less at year-end 2009 than the amounts reported as investments in property, plant and equipment for the Upstream in note 8. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations have been included in the capitalized costs for 2010 and 2009 in accordance with revised Financial Accounting Standards Board rules.

Capitalized Costs – Consolidated Subsidiaries	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
			(millions of dollars)				
As of December 31, 2010							
Property (acreage) costs – Proved	$ 8,031	$ 4,166	$ 199	$ 929	$ 1,451	$ 905	$ 15,681
– Unproved	24,697	1,260	75	418	229	211	26,890
Total property costs	$ 32,728	$ 5,426	$ 274	$ 1,347	$ 1,680	$ 1,116	$ 42,571
Producing assets	60,231	22,115	43,592	28,354	22,264	5,842	182,398
Incomplete construction	4,029	8,109	1,126	9,180	7,658	2,543	32,645
Total capitalized costs	$ 96,988	$ 35,650	$44,992	$38,881	$31,602	$ 9,501	$257,614
Accumulated depreciation and depletion	29,199	17,561	33,484	16,318	13,412	4,217	114,191
Net capitalized costs for consolidated subsidiaries	$ 67,789	$ 18,089	$11,508	$22,563	$18,190	$ 5,284	$143,423

Capitalized Costs – Equity Companies	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
As of December 31, 2010							
Property (acreage) costs – Proved	$ 76	$ —	$ 8	$ —	$ —	$ —	$ 84
– Unproved	2	—	—	—	—	—	2
Total property costs	$ 78	$ —	$ 8	$ —	$ —	$ —	$ 86
Producing assets	3,446	—	5,197	—	7,845	—	16,488
Incomplete construction	116	—	384	—	214	—	714
Total capitalized costs	$ 3,640	$ —	$ 5,589	$ —	$ 8,059	$ —	$ 17,288
Accumulated depreciation and depletion	1,418	—	4,252	—	2,484	—	8,154
Net capitalized costs for equity companies	$ 2,222	$ —	$ 1,337	$ —	$ 5,575	$ —	$ 9,134

Capitalized Costs – Consolidated Subsidiaries	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
As of December 31, 2009							
Property (acreage) costs – Proved	$ 3,225	$ 3,940	$ 204	$ 927	$ 1,257	$ 816	$ 10,369
– Unproved	1,233	1,117	52	416	237	198	3,253
Total property costs	$ 4,458	$ 5,057	$ 256	$ 1,343	$ 1,494	$ 1,014	$ 13,622
Producing assets	40,435	20,357	43,913	26,621	18,806	5,168	155,300
Incomplete construction	3,315	3,701	999	6,872	8,380	1,216	24,483
Total capitalized costs	$ 48,208	$ 29,115	$45,168	$34,836	$28,680	$ 7,398	$193,405
Accumulated depreciation and depletion	29,934	15,707	32,236	13,919	12,527	3,673	107,996
Net capitalized costs for consolidated subsidiaries	$ 18,274	$ 13,408	$12,932	$20,917	$16,153	$ 3,725	$ 85,409

Capitalized Costs – Equity Companies	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
As of December 31, 2009							
Property (acreage) costs – Proved	$ 76	$ —	$ 8	$ —	$ —	$ —	$ 84
– Unproved	1	—	—	—	—	—	1
Total property costs	$ 77	$ —	$ 8	$ —	$ —	$ —	$ 85
Producing assets	3,224	—	5,574	—	6,869	—	15,667
Incomplete construction	128	—	336	—	885	—	1,349
Total capitalized costs	$ 3,429	$ —	$ 5,918	$ —	$ 7,754	$ —	$ 17,101
Accumulated depreciation and depletion	1,340	—	4,493	—	2,048	—	7,881
Net capitalized costs for equity companies	$ 2,089	$ —	$ 1,425	$ —	$ 5,706	$ —	$ 9,220

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

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 2010 were $70,812 million, up $50,305 million from 2009, due primarily to the acquisition of XTO Energy Inc. 2009 costs were $20,507 million, up $4,691 million from 2008, due primarily to higher exploration and development costs as well as the inclusion in 2009 of costs incurred related to oil sands mining operations (see footnote 1 below). Total equity company costs incurred in 2010 were $914 million, down $105 million from 2009, due primarily to lower development costs.

Costs incurred in property acquisitions, exploration and development activities – Consolidated Subsidiaries	United States	Canada/ South America (1)	Europe	Africa	Asia	Australia/ Oceania	Total
			(millions of dollars)				
During 2010							
Property acquisition costs – Proved	$ 21,633	$ —	$ 41	$ 3	$ 115	$ —	$21,792
– Unproved	23,509	136	23	—	—	—	23,668
Exploration costs	690	527	550	453	545	228	2,993
Development costs	7,947	4,757	1,227	4,390	2,892	1,146	22,359
Total costs incurred for consolidated subsidiaries	$ 53,779	$ 5,420	$1,841	$4,846	$3,552	$ 1,374	$70,812
Costs incurred in property acquisitions, exploration and development activities – Equity Companies							
Property acquisition costs – Proved	$ —	$ —	$ —	$ —	$ —	$ —	$ —
– Unproved	1	—	—	—	—	—	1
Exploration costs	4	—	56	—	2	—	62
Development costs	323	—	225	—	303	—	851
Total costs incurred for equity companies	$ 328	$ —	$ 281	$ —	$ 305	$ —	$ 914
Costs incurred in property acquisitions, exploration and development activities – Consolidated Subsidiaries							
During 2009							
Property acquisition costs – Proved	$ 17	$ —	$ —	$ 600	$ 59	$ —	$ 676
– Unproved	188	353	1	5	62	—	609
Exploration costs	548	498	471	880	529	130	3,056
Development costs	2,482	2,394	3,384	4,596	2,542	768	16,166
Total costs incurred for consolidated subsidiaries	$ 3,235	$ 3,245	$3,856	$6,081	$3,192	$ 898	$20,507
Costs incurred in property acquisitions, exploration and development activities – Equity Companies							
Property acquisition costs – Proved	$ —	$ —	$ —	$ —	$ —	$ —	$ —
– Unproved	—	—	—	—	—	—	—
Exploration costs	1	—	54	—	—	—	55
Development costs	305	—	255	—	404	—	964
Total costs incurred for equity companies	$ 306	$ —	$ 309	$ —	$ 404	$ —	$ 1,019
During 2008							
Property acquisition costs – Proved	$ —	$ 1	$ —	$ —	$ 60	$ —	$ 61
– Unproved	281	125	25	82	13	76	602
Exploration costs	453	306	389	686	307	100	2,241
Development costs	2,255	907	1,634	4,783	2,890	443	12,912
Total costs incurred for consolidated subsidiaries	$ 2,989	$ 1,339	$2,048	$5,551	$3,270	$ 619	$15,816
Proportional interest of costs incurred of equity companies	$ 484	$ —	$ 241	$ —	$ 494	$ —	$ 1,219

(1) Costs incurred on synthetic oil reserves and bitumen mining operations in 2009 were $1,872 million, primarily on unproved property acquisition and development costs. Cold Lake bitumen operations had been included in costs incurred in previous years as an oil and gas operation.

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2008, 2009 and 2010.

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

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. In some cases, substantial new investments in additional wells and related facilities will be required to recover these proved reserves.

In accordance with the Securities and Exchange Commission's rules, the year-end reserves volumes for 2009 and 2010 as well as the reserves change categories for 2009 and 2010 shown in the following tables were calculated using average prices during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. The year-end reserves volumes for 2008 as well as the reserves change categories for 2008 shown in the following tables were calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow.

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, (2) new geologic, reservoir or production data or (3) changes in average prices and year-end costs that are used in the estimation of reserves. This category can also include 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 proved reserves tables, consolidated reserves and equity company reserves are reported separately. However, the Corporation does not view equity company 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 production and reserves that we report for these types of arrangements typically vary inversely with oil and gas price changes. As oil and gas prices increase, the cash flow and value received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2010 that were associated with production sharing contract arrangements was 16 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 or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Net proved undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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 in the Operating Summary due to volumes consumed or flared and inventory changes.

In accordance with the Securities and Exchange Commission's rules, bitumen extracted through mining activities and hydrocarbons from other non-traditional resources are reported as oil and gas reserves beginning in 2009.

The rules in 2009 adopted a reliable technology definition that permits reserves to be added based on technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated.

Major changes between 2009 year-end proved reserves and 2010 year-end proved reserves included the initial booking of the properties acquired in the XTO Energy Inc. transaction.

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

Crude Oil, Natural Gas Liquids, Synthetic Oil and Bitumen Proved Reserves

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.(1)	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ S. Amer(2)	Canada/ S. Amer.(3)	Total
						(millions of barrels)				
Net proved developed and undeveloped reserves of consolidated subsidiaries										
January 1, 2008	1,851	939	673	2,058	2,010	213	7,744			
Revisions	(104)	(70)	39	253	351	2	471			
Improved recovery	—	—	—	—	—	—	—			
Purchases	—	—	—	—	—	—	—			
Sales	(4)	(2)	(28)	—	(52)	—	(86)			
Extensions/discoveries	5	29	4	65	28	40	171			
Production	(104)	(84)	(155)	(239)	(118)	(24)	(724)			
December 31, 2008	1,644	812	533	2,137	2,219	231	7,576			
Proportional interest in proved reserves of equity companies										
End of year 2008	327	—	27	—	2,205	—	2,559			
Net proved developed and undeveloped reserves of consolidated subsidiaries										
January 1, 2009	1,644	812	533	2,137	2,219	231	7,576	—	—	7,576
Revisions	82	(610)(4)	93	(33)	(130)	9	(589)	2,099(4)	715	2,225
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—
Sales	(1)	—	(2)	—	—	—	(3)	—	—	(3)
Extensions/discoveries	3	—	—	53	15	71	142	—	—	142
Production	(112)	(30)	(137)	(250)	(105)	(23)	(657)	(44)	(24)	(725)
December 31, 2009	1,616	172	487	1,907	1,999	288	6,469	2,055	691	9,215
Proportional interest in proved reserves of equity companies										
January 1, 2009	327	—	27	—	2,205	—	2,559	—	—	2,559
Revisions	56	—	5	—	(54)	—	7	—	—	7
Improved recovery	—	—	—	—	15	—	15	—	—	15
Purchases	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	—	—	—	—	—	—	—	—
Production	(27)	—	(2)	—	(116)	—	(145)	—	—	(145)
December 31, 2009	356	—	30	—	2,050	—	2,436	—	—	2,436
Total liquids proved reserves at December 31, 2009	1,972	172	517	1,907	4,049	288	8,905	2,055	691	11,651

(1) *Includes total proved reserves attributable to Imperial Oil Limited of 694 million barrels in 2008, 63 million barrels in 2009 and 57 million barrels in 2010, as well as proved developed reserves of 488 million barrels in 2008, 62 million barrels in 2009 and 56 million barrels in 2010, and in addition, proved undeveloped reserves of 1 million barrels in 2009 and 1 million barrels in 2010, in which there is a 30.4 percent noncontrolling interest.*

(2) *Includes total proved reserves attributable to Imperial Oil Limited of 1,661 million barrels in 2009 and 1,715 million barrels in 2010, as well as proved developed reserves of 468 million barrels in 2009 and 519 million barrels in 2010, and in addition, proved undeveloped reserves of 1,193 million barrels in 2009 and 1,196 million barrels in 2010, in which there is a 30.4 percent noncontrolling interest.*

(3) *Includes total proved reserves attributable to Imperial Oil Limited of 691 million barrels in 2009 and 681 million barrels in 2010, as well as proved developed reserves of 691 million barrels in 2009 and 681 million barrels in 2010, in which there is a 30.4 percent noncontrolling interest.*

(4) *Total proved reserves of 630 million barrels at December 31, 2008, associated with the Cold Lake field in Canada are reported as bitumen reserves under the amended Securities and Exchange Commission's Rule 4-10 of Regulation S-X.*

Crude Oil, Natural Gas Liquids, Synthetic Oil and Bitumen Proved Reserves (continued)

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.(1)	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ S. Amer.(2)	Canada/ S. Amer.(3)	Total
						(millions of barrels)				
Net proved developed and undeveloped reserves of consolidated subsidiaries										
January 1, 2010	1,616	172	487	1,907	1,999	288	6,469	2,055	691	9,215
Revisions	57	10	53	89	49	7	265	89	14	368
Improved recovery	4	—	—	—	—	1	5	—	—	5
Purchases	374	—	—	—	4	—	378	—	—	378
Sales	(19)	—	—	(2)	—	—	(21)	—	—	(21)
Extensions/discoveries	43	11	4	34	90	—	182	—	—	182
Production	(123)	(30)	(121)	(229)	(119)	(21)	(643)	(42)	(24)	(709)
December 31, 2010	1,952	163	423	1,799	2,023	275	6,635	2,102	681	9,418
Proportional interest in proved reserves of equity companies										
January 1, 2010	356	—	30	—	2,050	—	2,436	—	—	2,436
Revisions	17	—	3	—	(30)	—	(10)	—	—	(10)
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	3	—	—	—	—	—	3	—	—	3
Production	(25)	—	(2)	—	(147)	—	(174)	—	—	(174)
December 31, 2010	351	—	31	—	1,873	—	2,255	—	—	2,255
Total liquids proved reserves at December 31, 2010	2,303	163	454	1,799	3,896	275	8,890	2,102	681	11,673

(See footnotes on previous page)

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

Crude Oil, Natural Gas Liquids, Synthetic Oil and Bitumen Proved Reserves (continued)

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.(1)	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ S. Amer.(2)	Canada/ S. Amer.(3)	Total
					(millions of barrels)					
Proved developed reserves, as of January 1, 2008										
Consolidated subsidiaries	1,327	682	518	1,202	1,033	185	4,947			
Equity companies	299	—	8	—	1,181	—	1,488			
Proved developed reserves, as of December 31, 2008										
Consolidated subsidiaries	1,257	580	410	1,284	1,097	165	4,793			
Equity companies	264	—	9	—	1,417	—	1,690			
Proved developed reserves, as of December 31, 2009										
Consolidated subsidiaries	1,211	152	376	1,122	1,268	153	4,282	468	691	5,441
Equity companies	279	—	10	—	1,608	—	1,897	—	—	1,897
Proved undeveloped reserves, as of December 31, 2009										
Consolidated subsidiaries	405	20	111	785	731	135	2,187	1,587	—	3,774
Equity companies	77	—	20	—	442	—	539	—	—	539
Total liquids proved reserves at December 31, 2009	1,972	172	517	1,907	4,049	288	8,905	2,055	691	11,651
Proved developed reserves, as of December 31, 2010										
Consolidated subsidiaries	1,478	133	361	1,055	1,306	139	4,472	519	681	5,672
Equity companies	271	—	21	—	1,623	—	1,915	—	—	1,915
Proved undeveloped reserves, as of December 31, 2010										
Consolidated subsidiaries	474	30	62	744	717	136	2,163	1,583	—	3,746
Equity companies	80	—	10	—	250	—	340	—	—	340
Total liquids proved reserves at December 31, 2010	2,303	163	454	1,799	3,896	275	8,890	2,102	681	11,673

(See footnotes on page 108)

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent
	United States	Canada/ S. Amer.[(1)]	Europe	Africa	Asia	Australia/ Oceania	Total	Total All Products[(2)]
	(billions of cubic feet)							(millions of oil-equivalent barrels)
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2008	13,172	1,559	6,512	1,006	8,604	1,757	32,610	
Revisions	(1,056)	88	(193)	(55)	1,855	(4)	635	
Improved recovery	—	—	—	—	—	—	—	
Purchases	—	—	—	—	—	—	—	
Sales	(12)	(17)	(8)	—	(24)	—	(61)	
Extensions/discoveries	229	16	10	12	7	412	686	
Production	(555)	(263)	(876)	(45)	(585)	(144)	(2,468)	
December 31, 2008	11,778	1,383	5,445	918	9,857	2,021	31,402	
Proportional interest in proved reserves of equity companies								
End of year 2008	112	—	11,839	—	22,526	—	34,477	
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2009	11,778	1,383	5,445	918	9,857	2,021	31,402	12,810
Revisions	320	248	79	45	(980)	40	(248)	2,183
Improved recovery	—	—	—	—	—	—	—	—
Purchases	8	—	—	—	—	—	8	1
Sales	(10)	(2)	(1)	—	—	—	(13)	(5)
Extensions/discoveries	158	—	—	—	11	5,507	5,676	1,088
Production	(566)	(261)	(800)	(43)	(585)	(128)	(2,383)	(1,122)
December 31, 2009	11,688	1,368	4,723	920	8,303	7,440	34,442	14,955
Proportional interest in proved reserves of equity companies								
January 1, 2009	112	—	11,839	—	22,526	—	34,477	8,305
Revisions	8	—	186	—	189	—	383	71
Improved recovery	—	—	—	—	—	—	—	15
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	18	—	—	—	18	3
Production	(6)	—	(593)	—	(714)	—	(1,313)	(364)
December 31, 2009	114	—	11,450	—	22,001	—	33,565	8,030
Total proved reserves at December 31, 2009	11,802	1,368	16,173	920	30,304	7,440	68,007	22,985

(1) Includes total proved reserves attributable to Imperial Oil Limited of 593 billion cubic feet in 2008, 590 billion cubic feet in 2009 and 576 billion cubic feet in 2010, as well as proved developed reserves of 513 billion cubic feet in 2008, 526 billion cubic feet in 2009 and 507 billion cubic feet in 2010, and in addition, proved undeveloped reserves of 64 billion cubic feet in 2009 and 69 billion cubic feet in 2010, in which there is a 30.4 percent noncontrolling interest.

(2) Natural gas is converted to oil-equivalent basis at six million cubic feet per one thousand barrels.

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent
	United States	Canada/ S. Amer.[1]	Europe	Africa	Asia	Australia/ Oceania	Total	Total All Products[2]
	(billions of cubic feet)							(millions of oil-equivalent barrels)
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2010	11,688	1,368	4,723	920	8,303	7,440	34,442	14,955
Revisions	832	123	(26)	6	(333)	42	644	475
Improved recovery	—	—	—	—	—	—	—	5
Purchases	12,774	—	15	—	—	—	12,789	2,510
Sales	(104)	(2)	—	—	—	—	(106)	(38)
Extensions/discoveries	1,861	3	49	25	25	1	1,964	509
Production	(1,057)	(234)	(719)	(43)	(735)	(132)	(2,920)	(1,196)
December 31, 2010	25,994	1,258	4,042	908	7,260	7,351	46,813	17,220
Proportional interest in proved reserves of equity companies								
January 1, 2010	114	—	11,450	—	22,001	—	33,565	8,030
Revisions	8	—	(4)	—	231	—	235	30
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	24	—	—	—	24	7
Production	(5)	—	(724)	—	(1,093)	—	(1,822)	(478)
December 31, 2010	117	—	10,746	—	21,139	—	32,002	7,589
Total proved reserves at December 31, 2010	26,111	1,258	14,788	908	28,399	7,351	78,815	24,809

(See footnotes on previous page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent
	United States	Canada/ S. Amer.(1)	Europe	Africa	Asia	Australia/ Oceania	Total	Total All Products(2)
	(billions of cubic feet)							(millions of oil-equivalent barrels)
Proved developed reserves, as of January 1, 2008								
Consolidated subsidiaries	8,373	1,303	5,064	773	4,562	1,403	21,478	
Equity companies	104	—	9,679	—	9,459	—	19,242	
Proved developed reserves, as of December 31, 2008								
Consolidated subsidiaries	7,835	1,148	4,426	738	5,257	1,346	20,750	
Equity companies	96	—	9,284	—	12,619	—	21,999	
Proved developed reserves, as of December 31, 2009								
Consolidated subsidiaries	7,492	1,200	3,920	739	7,407	1,262	22,020	9,111
Equity companies	90	—	8,862	—	17,799	—	26,751	6,356
Proved undeveloped reserves, as of December 31, 2009								
Consolidated subsidiaries	4,196	168	803	181	896	6,178	12,422	5,844
Equity companies	24	—	2,588	—	4,202	—	6,814	1,674
Total proved reserves at December 31, 2009	11,802	1,368	16,173	920	30,304	7,440	68,007	22,985
Proved developed reserves, as of December 31, 2010								
Consolidated subsidiaries	15,344	1,077	3,516	711	6,593	1,174	28,415	10,408
Equity companies	97	—	8,167	—	20,494	—	28,758	6,708
Proved undeveloped reserves, as of December 31, 2010								
Consolidated subsidiaries	10,650	181	526	197	667	6,177	18,398	6,812
Equity companies	20	—	2,579	—	645	—	3,244	881
Total proved reserves at December 31, 2010	26,111	1,258	14,788	908	28,399	7,351	78,815	24,809

(See footnotes on page 111)

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 was computed through 2008 by applying year-end prices, costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. Beginning in 2009, the standardized measure of discounted future net cash flows is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to 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 first-day-of-the-month average prices, which represent discrete points 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/ South America(1)	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2008							
Future cash inflows from sales of oil and gas	$104,441	$ 22,952	$71,879	$ 74,426	$ 80,314	$10,437	$364,449
Future production costs	44,230	13,113	19,485	24,403	22,826	5,334	129,391
Future development costs	19,828	6,156	8,765	16,064	11,496	2,134	64,443
Future income tax expenses	17,857	961	24,729	16,870	26,218	917	87,552
Future net cash flows	$ 22,526	$ 2,722	$18,900	$ 17,089	$ 19,774	$ 2,052	$ 83,063
Effect of discounting net cash flows at 10%	13,107	(239)	7,602	8,052	13,031	941	42,494
Discounted future net cash flows	$ 9,419	$ 2,961	$11,298	$ 9,037	$ 6,743	$ 1,111	$ 40,569
Proportional interest in standardized measure of discounted future net cash flows related to proved reserves of equity companies	$ 2,354	$ —	$12,507	$ —	$ 30,588	$ —	$ 45,449
Consolidated Subsidiaries							
As of December 31, 2009							
Future cash inflows from sales of oil and gas	$112,408	$ 147,597	$54,074	$110,475	$121,110	$39,127	$584,791
Future production costs	47,660	62,241	16,412	28,679	29,769	12,571	197,332
Future development costs	15,544	25,738	12,565	15,155	10,256	11,655	90,913
Future income tax expenses	22,058	14,572	16,065	32,784	46,286	4,739	136,504
Future net cash flows	$ 27,146	$ 45,046	$ 9,032	$ 33,857	$ 34,799	$10,162	$160,042
Effect of discounting net cash flows at 10%	15,563	31,980	2,569	14,192	20,698	9,194	94,196
Discounted future net cash flows	$ 11,583	$ 13,066	$ 6,463	$ 19,665	$ 14,101	$ 968	$ 65,846
Equity Companies							
As of December 31, 2009							
Future cash inflows from sales of oil and gas	$ 19,705	$ —	$94,401	$ —	$180,253	$ —	$294,359
Future production costs	5,847	—	60,869	—	54,493	—	121,209
Future development costs	2,862	—	3,220	—	2,759	—	8,841
Future income tax expenses	—	—	12,003	—	44,733	—	56,736
Future net cash flows	$ 10,996	$ —	$18,309	$ —	$ 78,268	$ —	$107,573
Effect of discounting net cash flows at 10%	6,332	—	9,845	—	42,086	—	58,263
Discounted future net cash flows	$ 4,664	$ —	$ 8,464	$ —	$ 36,182	$ —	$ 49,310
Total consolidated and equity interests in standardized measure of discounted future net cash flows	$ 16,247	$ 13,066	$14,927	$ 19,665	$ 50,283	$ 968	$115,156

(1) *Includes discounted future net cash flows attributable to Imperial Oil Limited of $1,033 million in 2008 and $10,088 million in 2009, in which there is a 30.4 percent noncontrolling interest.*

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ South America(1)	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2010							
Future cash inflows from sales of oil and gas	$221,298	$ 184,671	$60,086	$137,476	$156,337	$55,087	$814,955
Future production costs	76,992	69,765	15,246	31,189	36,318	16,347	245,857
Future development costs	28,905	22,130	12,155	15,170	13,716	11,652	103,728
Future income tax expenses	44,128	21,798	21,736	46,145	59,477	9,591	202,875
Future net cash flows	$ 71,273	$ 70,978	$10,949	$ 44,972	$ 46,826	$17,497	$262,495
Effect of discounting net cash flows at 10%	39,545	45,607	2,765	18,046	28,883	13,411	148,257
Discounted future net cash flows	$ 31,728	$ 25,371	$ 8,184	$ 26,926	$ 17,943	$ 4,086	$114,238
Equity Companies							
As of December 31, 2010							
Future cash inflows from sales of oil and gas	$ 26,110	$ –	$73,222	$ –	$232,334	$ –	$331,666
Future production costs	6,369	–	49,010	–	73,508	–	128,887
Future development costs	2,883	–	2,719	–	2,523	–	8,125
Future income tax expenses	–	–	8,348	–	57,041	–	65,389
Future net cash flows	$ 16,858	$ –	$13,145	$ –	$ 99,262	$ –	$129,265
Effect of discounting net cash flows at 10%	9,612	–	6,857	–	51,512	–	67,981
Discounted future net cash flows	$ 7,246	$ –	$ 6,288	$ –	$ 47,750	$ –	$ 61,284
Total consolidated and equity interests in standardized measure of discounted future net cash flows	$ 38,974	$ 25,371	$14,472	$ 26,926	$ 65,693	$ 4,086	$175,522

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $19,834 million in 2010, in which there is a 30.4 percent noncontrolling interest.

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

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

Consolidated Subsidiaries	2008
	(millions of dollars)
Discounted future net cash flows as of December 31, 2007	$ 126,173
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	(303)
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	(62,685)
Development costs incurred during the year	11,649
Net change in prices, lifting and development costs	(178,960)
Revisions of previous reserves estimates	7,652
Accretion of discount	21,463
Net change in income taxes	115,580
Total change in the standardized measure during the year for consolidated subsidiaries	$ (85,604)
Discounted future net cash flows as of December 31, 2008	$ 40,569

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

Consolidated and Equity Interests	2009		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2008	$ 40,569	$ 45,449	$ 86,018
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	2,138	280	2,418
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	(35,384)	(10,288)	(45,672)
Development costs incurred during the year	13,549	1,017	14,566
Net change in prices, lifting and development costs	51,627	9,245	60,872
Revisions of previous reserves estimates	8,805	858	9,663
Accretion of discount	6,943	5,214	12,157
Net change in income taxes	(22,401)	(2,465)	(24,866)
Total change in the standardized measure during the year	$ 25,277	$ 3,861	$ 29,138[(1)(2)]
Discounted future net cash flows as of December 31, 2009	$ 65,846	$ 49,310	$ 115,156

(1) Discounted future net cash flows associated with synthetic oil reserves and bitumen mining operations in 2009 were $5,268 million. Cold Lake bitumen operations had been included in discounted future net cash flows in previous years as an oil and gas operation.

(2) The estimated impact of adopting the reliable technology definition and changing from year-end price to first-day-of-the-month average prices in the Securities and Exchange Commission's Rule 4-10 of Regulation S-X was de minimis on discounted future net cash flows for consolidated and equity subsidiaries in 2009.

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

Consolidated and Equity Interests (continued)

	2010		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2009	$ 65,846	$ 49,310	$ 115,156
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	20,093	210	20,303
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	(46,078)	(16,050)	(62,128)
Development costs incurred during the year	20,975	843	21,818
Net change in prices, lifting and development costs	61,612	23,135	84,747
Revisions of previous reserves estimates	14,770	3,605	18,375
Accretion of discount	10,399	5,775	16,174
Net change in income taxes	(33,379)	(5,544)	(38,923)
Total change in the standardized measure during the year	$ 48,392	$ 11,974	$ 60,366
Discounted future net cash flows as of December 31, 2010	$ 114,238	$ 61,284	$ 175,522

OPERATING SUMMARY (unaudited)

	2010	2009	2008	2007	2006
			(thousands of barrels daily)		
Production of crude oil, natural gas liquids, synthetic oil and bitumen					
Net production					
United States	408	384	367	392	414
Canada/South America	263	267	292	324	354
Europe	335	379	428	480	520
Africa	628	685	652	717	781
Asia	730	607	599	629	535
Australia/Oceania	58	65	67	74	77
Worldwide	2,422	2,387	2,405	2,616	2,681
			(millions of cubic feet daily)		
Natural gas production available for sale					
Net production					
United States	2,596	1,275	1,246	1,468	1,625
Canada/South America	569	643	640	808	935
Europe	3,836	3,689	3,949	3,810	4,086
Africa	14	19	32	26	–
Asia	4,801	3,332	2,870	2,883	2,358
Australia/Oceania	332	315	358	389	330
Worldwide	12,148	9,273	9,095	9,384	9,334
			(thousands of oil-equivalent barrels daily)		
Oil-equivalent production *(1)*	4,447	3,932	3,921	4,180	4,237
			(thousands of barrels daily)		
Refinery throughput					
United States	1,753	1,767	1,702	1,746	1,760
Canada	444	413	446	442	442
Europe	1,538	1,548	1,601	1,642	1,672
Asia Pacific	1,249	1,328	1,352	1,416	1,434
Other Non-U.S.	269	294	315	325	295
Worldwide	5,253	5,350	5,416	5,571	5,603
Petroleum product sales *(2)*					
United States	2,511	2,523	2,540	2,717	2,729
Canada	450	413	444	461	473
Europe	1,611	1,625	1,712	1,773	1,813
Asia Pacific and other Eastern Hemisphere	1,562	1,588	1,646	1,701	1,763
Latin America	280	279	419	447	469
Worldwide	6,414	6,428	6,761	7,099	7,247
Gasoline, naphthas	2,611	2,573	2,654	2,850	2,866
Heating oils, kerosene, diesel oils	1,951	2,013	2,096	2,094	2,191
Aviation fuels	476	536	607	641	651
Heavy fuels	603	598	636	715	682
Specialty petroleum products	773	708	768	799	857
Worldwide	6,414	6,428	6,761	7,099	7,247
			(thousands of metric tons)		
Chemical prime product sales					
United States	9,815	9,649	9,526	10,855	10,703
Non-U.S.	16,076	15,176	15,456	16,625	16,647
Worldwide	25,891	24,825	24,982	27,480	27,350

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.
(2) Petroleum product sales data reported net of purchases/sales contracts with the same counterparty.

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 25, 2011

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Beverley A. Babcock, Randall M. Ebner and Robert N. Schleckser 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 25, 2011
/s/ MICHAEL J. BOSKIN (Michael J. Boskin)	Director	February 25, 2011
/s/ PETER BRABECK-LETMATHE (Peter Brabeck-Letmathe)	Director	February 25, 2011
/s/ LARRY R. FAULKNER (Larry R. Faulkner)	Director	February 25, 2011

/s/ JAY S. FISHMAN (Jay S. Fishman)	Director	February 25, 2011
/s/ KENNETH C. FRAZIER (Kenneth C. Frazier)	Director	February 25, 2011
/s/ WILLIAM W. GEORGE (William W. George)	Director	February 25, 2011
/s/ MARILYN CARLSON NELSON (Marilyn Carlson Nelson)	Director	February 25, 2011
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director	February 25, 2011
/s/ STEVEN S REINEMUND (Steven S Reinemund)	Director	February 25, 2011
/s/ EDWARD E. WHITACRE, JR. (Edward E. Whitacre, Jr.)	Director	February 25, 2011
/s/ DONALD D. HUMPHREYS (Donald D. Humphreys)	Treasurer (Principal Financial Officer)	February 25, 2011
/s/ PATRICK T. MULVA (Patrick T. Mulva)	Controller (Principal Accounting Officer)	February 25, 2011

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, 2006).
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, 2007).
10(iii)(a.1)	2003 Incentive Program (incorporated by reference to Exhibit 10(iii)(a.1) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008).*
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 2009).*
10(iii)(a.3)	Form of restricted stock agreement with executive officers (incorporated by reference to Exhibit 99.2 to the Registrant's Report on Form 8-K on November 30, 2010).*
10(iii)(b.1)	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 99.3 to the Registrant's Report on Form 8-K on December 1, 2009).*
10(iii)(b.2)	Form of Earnings Bonus Unit granted to executive officers (incorporated by reference to Exhibit 99.1 to the Registrant's Report on Form 8-K on November 30, 2010).*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 99.1 to the Registrant's Report on Form 8-K on November 2, 2007).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant's Report on Form 8-K on October 12, 2006).*
10(iii)(c.3)	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant's Report on Form 8-K on October 12, 2006).*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f.1) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009).*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by reference to Exhibit 99.2 to the Registrant's Report on Form 8-K on September 27, 2007).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors (incorporated by reference to Exhibit 10(iii)(f.3) to the Registrant's Annual Report on Form 10-K for 2009).*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated September 28, 2009 (incorporated by reference to Exhibit 99.1 to the Registrant's Report on Form 8-K on October 28, 2009).*
10(iii)(f.5)	Extended Provisions for Restricted Stock Unit Agreements-Settlement in Shares.*

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Index to Financial Statements

INDEX TO EXHIBITS—(continued)

10(iii)(g.3)	1984 Mobil Compensation Management Retention Plan, as amended and restated on September 27, 2007 (incorporated by reference to Exhibit 99.1 to the Registrant's Report on Form 8-K on September 27, 2007).*
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 2008).
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.
101	Interactive data files.

* 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.

November 23, 2010

Exxon Mobil Corporation
Extended Provisions for Restricted Stock Unit Agreements - Settlement in Shares

1. **Effective Date and Credit of Restricted Stock Units.** If Grantee completes, signs, and returns the signature page of this Agreement to the Corporation in Dallas County, Texas, U.S.A. on or before March 9, 2011, this Agreement will become effective the date the Corporation receives and accepts the signature page in Dallas County, Texas, U.S.A. After this agreement becomes effective, the Corporation will credit to Grantee the number of restricted stock units specified on the signature page. Subject to the terms and conditions of this Agreement, each restricted stock unit ("unit") will entitle Grantee to receive in settlement of the unit one share of the Corporation's common stock.

2. **Conditions.** If credited, the units will be subject to the provisions of this Agreement, and to such regulations and requirements as the administrative authority of the Program may establish from time to time. The units will be credited to Grantee only on the condition that Grantee accepts such provisions, regulations, and requirements.

3. **Restrictions and Risk of Forfeiture.** During the applicable restricted periods specified in section 4 of this Agreement,

(a) the units under restriction may not be sold, assigned, transferred, pledged, or otherwise disposed of or encumbered, and any attempt to do so will be null and void; and
(b) the units under restriction may be forfeited as provided in section 6.

4. **Restricted Periods.** The restricted periods will commence when the units are credited to Grantee and, unless the units have been forfeited earlier under section 6, will expire as follows, whether or not Grantee is still an employee:

(a) with respect to 50% of the units, on November 23, 2015; and
(b) with respect to the remaining units, on the later to occur of
  (i) November 23, 2020, or
  (ii) the first day of the calendar year immediately following the year in which Grantee terminates;
  exceptthat
(c) the restricted periods will automatically expire with respect to all shares on the death of Grantee.

5. **No Obligation to Credit Units.** The Corporation will have no obligation to credit any units and will have no other obligation to Grantee with respect to the subject matter of this Agreement if Grantee fails to complete, sign, and return the signature page of this Agreement on or before March 9, 2011. In addition, whether or not Grantee has completed, signed, and returned the signature page, the Corporation will have no obligation to credit any units and will have no other obligation to Grantee with respect to the subject matter of this Agreement if, before the units are credited:

(a) Grantee terminates (other than by death) before standard retirement time within the meaning of the Program, except to the extent the administrative authority of the Program determines Grantee may receive units under this Agreement; or
(b) Grantee is determined to have engaged in detrimental activity within the meaning of the Program; or
(c) Grantee fails to provide the Corporation with cash for any required taxes due upon crediting the units, if Grantee is required to do so under section 7.

6. **Forfeiture of Units After Crediting.** Until the applicable restricted period specified in section 4 has expired, the units under restriction will be forfeited or subject to forfeiture in the following circumstances:

Termination
If Grantee terminates (other than by death) before standard retirement time within the meaning of the Program, all units for which the applicable restricted periods have not expired will be automatically forfeited as of the date of termination, except to the extent the administrative authority determines Grantee may retain units issued under this Agreement.

Detrimental activity
If Grantee is determined to have engaged in detrimental activity within the meaning of the Program, either before or after termination, all units for which the applicable restricted periods have not expired will be automatically forfeited as of the date of such determination.

Attempted transfer
The units are subject to forfeiture in the discretion of the administrative authority if Grantee attempts to sell, assign, transfer, pledge, or otherwise dispose of or encumber them during the applicable restricted periods.

Applicable law

The units are subject to forfeiture in whole or in part as the administrative authority deems necessary in order to comply with applicable law.

7. **Taxes.** Notwithstanding the restrictions on transfer that otherwise apply, the Corporation in its sole discretion may withhold units or shares, either at the time of issuance, at the time the applicable restricted periods expire, or at any other time in order to satisfy any required withholding, social security, and similar taxes or contributions (collectively, "required taxes"). Withheld units or shares may be retained by the Corporation or sold on behalf of Grantee. If the Corporation does not withhold units or shares to satisfy required taxes, in the alternative the Corporation may require Grantee to deposit with the Corporation cash in an amount determined by the Corporation to be necessary to satisfy required taxes. Notwithstanding any other provision of this Agreement, the Corporation will be under no obligation to credit units or to deliver shares to Grantee in settlement of any units if Grantee fails timely to deposit such amount with the Corporation. The Corporation in its sole discretion may also withhold any required taxes from dividends paid on the units.

8. **Form of Units; No Shareholder Status.** The units will be represented by book-entry credits in records maintained by or on behalf of the Corporation. Units will be unfunded and unsecured promises by the Corporation to deliver shares in the future upon the terms and subject to the conditions of this Agreement. Grantee will not be a shareholder of the Corporation with respect to units prior to the time shares are actually registered in Grantee's name in settlement of such units in accordance with section 9.

9. **Settlement of Units.** If and when the applicable restricted period expires with respect to any units, subject to section 7, the Corporation will issue shares, free of restriction and registered in the name of Grantee, in settlement of such units. Such shares will be delivered promptly after such expiration to or for the account of Grantee either in certificated form or by book-entry transfer in accordance with the procedures of the administrative authority in effect at the time.

10. **Change in Capitalization.** If during the applicable restricted periods a stock split, stock dividend, or other relevant change in capitalization of the Corporation occurs, the administrative authority will make such adjustments in the number of units credited to Grantee, or in the number and type of securities deliverable to Grantee in settlement of such units and used in determining dividend equivalent amounts, as the administrative authority may determine to be appropriate. Any resulting new units or securities credited with respect to previously credited units that are still restricted under this Agreement will be delivered to and held by or on behalf of the Corporation and will be subject to the same provisions, restrictions, and requirements as those previously credited units.

11. **Limits on the Corporation's Obligations.** Notwithstanding anything else contained in this Agreement, under no circumstances will the Corporation be required to credit any units or issue or deliver any shares in settlement of units if doing so would violate any law or listing requirement that the administrative authority determines to be applicable, or if Grantee has failed to provide for required taxes pursuant to section 7.

12. **Receipt or Access to Program.** Grantee acknowledges receipt of or access to the full text of the Program.

13. **Dividend Equivalents.** The Corporation will pay to Grantee cash with respect to each credited unit corresponding in amount, currency, and timing to cash dividends that would be payable with respect to a share of common stock outstanding on each record date that occurs during the applicable restricted period. Alternatively, the administrative authority may determine to reinvest such dividend equivalents in additional units which will be held subject to all the terms and conditions otherwise applicable to units under this Agreement.

14. **Addresses for Communications.** To facilitate communications regarding this Agreement, Grantee agrees to notify the Corporation promptly of changes in current mailing and email addresses. Communications to the Corporation in connection with this Agreement should be directed to the Incentive Processing Office at the address given on the signature page of this Agreement, or to such other address as the Corporation may designate by further notice to Grantee.

15. **Transfer of Personal Data.** The administration of the Program and this Agreement involves the transfer of personal data about Grantee between and among the Corporation, selected affiliates of the Corporation, and third-party service providers such as Morgan Stanley Smith Barney and Computershare (the Corporation's transfer agent). This data includes Grantee's name, age, contact information, work location, employment status, tax status, and related information. By accepting this award, Grantee authorizes the transfer of this data.

16. **<u>No Employment Contract or Entitlement to Other or Future Awards</u>.** This Agreement, the Corporation's incentive programs, and Grantee's selection for incentive awards do not imply or form a part of any contract or assurance of employment, and they do not in any way limit or restrict the ability of Grantee's employer to terminate Grantee's employment. Grantee acknowledges that the Corporation maintains and administers its incentive programs entirely in its discretion and that Grantee is not entitled to any other or future incentive awards of any kind in addition to those that have already been granted.

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

18. **<u>Entire Agreement</u>.** This Agreement constitutes the entire understanding between Grantee and the Corporation with respect to the subject matter of this Agreement.

EXXON MOBIL CORPORATION

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2010	2009	2008	2007	2006
	(millions of dollars)				
Income from continuing operations attributable to ExxonMobil	$30,460	$19,280	$45,220	$40,610	$39,500
Excess/(shortfall) of dividends over earnings of affiliates accounted for by the equity method	(596)	(483)	921	(714)	(579)
Provision for income taxes	21,561	15,119	36,530	29,864	27,902
Capitalized interest	(126)	(25)	(118)	(181)	(160)
Noncontrolling interests in earnings of consolidated subsidiaries	938	378	1,647	1,005	1,051
	52,237	34,269	84,200	70,584	67,714
Fixed Charges:					
Interest expense—borrowings	28	48	175	110	119
Capitalized interest	532	425	510	557	530
Rental cost representative of interest factor	709	909	886	729	797
	1,269	1,382	1,571	1,396	1,446
Total adjusted earnings available for payment of fixed charges	$53,506	$35,651	$85,771	$71,980	$69,160
Number of times fixed charges are earned	42.2	25.8	54.6	51.6	47.8

Subsidiaries of the Registrant (1), (2) and (3) — at December 31, 2010

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Abu Dhabi Petroleum Company Limited (5)	23.75	United Kingdom
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
Barnett Gathering, LP	100	Texas
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
Cross Timbers Energy Services, Inc.	100	Texas
Ellora Energy Inc.	100	Delaware
Esso Australia Resources Pty Ltd	100	Australia
Esso Deutschland GmbH	100	Germany
Esso Erdgas Beteiligungsgesellschaft mbH	100	Germany
Esso Exploration and Production Angola (Block 31) Limited	100	Bahamas
Esso Exploration and Production Angola (Overseas) 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 (Offshore East) Limited	100	Nigeria
Esso Exploration and Production Nigeria Limited	100	Nigeria
Esso Exploration and Production UK Limited	100	United Kingdom
Esso Exploration Angola (Block 15) Limited	100	Bahamas
Esso Exploration Angola (Block 17) Limited	100	Bahamas
Esso Highlands Limited	100	Papua New Guinea
Esso Holding Company Singapore Limited	100	Bahamas
Esso Ireland Limited	100	Ireland
Esso Italiana S.r.l.	100	Italy
Esso Malaysia Berhad	65	Malaysia
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	United Kingdom
Esso Pipeline Investments Limited	100	Bahamas
Esso Raffinage S.A.F.	82.89	France
Esso Societe Anonyme Francaise	82.89	France
Esso (Thailand) Public Company Limited	65.99	Thailand
Esso Trading Company of Abu Dhabi	100	Delaware
Exxon Azerbaijan Limited	100	Bahamas
Exxon Chemical Arabia Inc.	100	Delaware
Exxon Luxembourg Holdings LLC	100	Delaware
Exxon Mobile Bay Limited Partnership	100	Delaware
Exxon Neftegas Limited	100	Bahamas
Exxon Overseas Corporation	100	Delaware

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Exxon Overseas Investment Corporation	100	Delaware
ExxonMobil Abu Dhabi Offshore Petroleum Company Limited	100	Bahamas
ExxonMobil Alaska Production Inc.	100	Delaware
ExxonMobil Asia Pacific Pte. Ltd.	100	Singapore
ExxonMobil Australia Pty Ltd	100	Australia
ExxonMobil Belgium Finance	100	Belgium
ExxonMobil Canada Energy	100	Canada
ExxonMobil Canada Finance Company	100	Canada
ExxonMobil Canada Hibernia Company Ltd.	100	Canada
ExxonMobil Canada Ltd.	100	Canada
ExxonMobil Canada Properties	100	Canada
ExxonMobil Canada Resources Company	100	Canada
ExxonMobil Capital N.V.	100	Netherlands
ExxonMobil Catalyst Technologies LLC	100	Delaware
ExxonMobil Central Europe Holding GmbH	100	Germany
ExxonMobil Chemical France	99.77	France
ExxonMobil Chemical Holland B.V.	100	Netherlands
ExxonMobil Chemical Limited	100	United Kingdom
ExxonMobil China Petroleum & Petrochemical Company Limited	100	Bahamas
ExxonMobil de Colombia S.A.	99.686	Colombia
ExxonMobil Delaware Holdings Inc.	100	Delaware
ExxonMobil Development Company	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 Finance Company Limited	100	United Kingdom
ExxonMobil Financial Services B.V.	100	Netherlands
ExxonMobil France Holding SAS	100	France
ExxonMobil Gas Marketing Deutschland GmbH	100	Germany
ExxonMobil Gas Marketing Deutschland GmbH & Co. KG	50	Germany
ExxonMobil Gas Marketing Europe Limited	100	United Kingdom
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	100	Luxembourg
ExxonMobil Italiana Gas S.r.l.	100	Italy
ExxonMobil Kazakhstan Inc.	100	Bahamas
ExxonMobil Kazakhstan Ventures Inc.	100	Delaware
ExxonMobil Libya Limited	100	Bahamas
ExxonMobil Luxembourg	100	Luxembourg
ExxonMobil Luxembourg UK	100	Luxembourg
ExxonMobil Malaysia Sdn Bhd	100	Malaysia
ExxonMobil Marine Limited	100	United Kingdom
ExxonMobil Middle East Gas Marketing Limited	100	Bahamas
ExxonMobil Oil & Gas Investments Limited	100	Bahamas
ExxonMobil Oil Corporation	100	New York

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
ExxonMobil Oil Indonesia Inc.	100	Cayman Islands
ExxonMobil Permian Basin Inc.	100	Delaware
ExxonMobil Petroleum & Chemical	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 Qatargas (II) Limited	100	Bahamas
ExxonMobil Qatargas (II) Terminal Company Limited	100	Bahamas
ExxonMobil Ras Laffan (III) Limited	100	Bahamas
ExxonMobil Rasgas Inc.	100	Delaware
ExxonMobil Research and Engineering Company	100	Delaware
ExxonMobil Sales and Supply LLC	100	Delaware
ExxonMobil Southwest Holdings Inc.	100	Delaware
ExxonMobil Ventures Funding Ltd.	100	Bahamas
ExxonMobil Yugen Kaisha	100	Japan
Fina Antwerp Olefins N.V. (5)	35	Belgium
Fujian Refining & Petrochemical Co. Ltd. (5)	25	China
Golden Pass LNG Terminal Investments LLC	100	Delaware
Golden Pass LNG Terminal LLC (5)	17.6	Delaware
Imperial Oil Limited	69.6	Canada
Imperial Oil (an Ontario General Partnership)	69.6	Canada
Imperial Oil Resources (an Alberta limited partnership)	69.6	Canada
Imperial Oil Resources Limited	69.6	Canada
Imperial Oil Resources N.W.T. Limited	69.6	Canada
Imperial Oil Resources Ventures Limited	69.6	Canada
Infineum Holdings B.V. (5)	49.96	Netherlands
Kyokuto Petroleum Industries, Ltd. (4) (5)	50	Japan
Metroplex Barnett Shale LLC	100	Delaware
Mineraloelraffinerie Oberrhein GmbH & Co. KG (5)	25	Germany
Mobil Australia Resources Company Pty Limited	100	Australia
Mobil California Exploration & Producing Asset Company	100	Delaware
Mobil Caspian Pipeline Company	100	Delaware
Mobil Cepu Ltd.	100	Bermuda
Mobil Cerro Negro, Ltd.	100	Bahamas
Mobil Corporation	100	Delaware
Mobil Equatorial Guinea Inc.	100	Delaware
Mobil Erdgas-Erdoel GmbH	100	Germany
Mobil Exploration Indonesia Inc.	100	Cayman Islands
Mobil North Sea Investment Limited	100	United Kingdom
Mobil North Sea L.L.C.	100	Delaware
Mobil North Sea Production Limited	100	United Kingdom
Mobil Oil Australia Pty Ltd	100	Australia
Mobil Oil Exploration & Producing Southeast Inc.	100	Delaware
Mobil Oil New Zealand Limited	100	New Zealand
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

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Mobil Yanbu Petrochemical Company Inc.	100	Delaware
Mobil Yanbu Refining Company Inc.	100	Delaware
Nederlandse Aardolie Maatschappij B.V. (4) (5)	50	Netherlands
Papua New Guinea Liquefied Natural Gas Global Company LDC (5)	33.2	Bahamas
Qatar Liquefied Gas Company Limited (5)	10	Qatar
Qatar Liquefied Gas Company Limited (2) (5)	24.15	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (5)	24.999	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (II) (5)	31.006	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (3) (5)	30	Qatar
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 a responsabilita limitata Raffineria Padana Olii Minerali - S.A.R.P.O.M. S.r.l.	74.14	Italy
South Hook LNG Terminal Company Limited (5)	24.15	United Kingdom
Tengizchevroil, LLP (5)	25	Kazakhstan
Terminale GNL Adriatico S.r.l. (5)	45	Italy
Tonen Chemical Corporation	50.076	Japan
Tonen Chemical Nasu Corporation	50.076	Japan
TonenGeneral Sekiyu K.K.	50.076	Japan
Toray Tonen Specialty Separator Godo Kaisha (5)	25.04	Japan
Trend Gathering & Treating, LP	100	Texas
XH, LLC	100	Delaware
XTO Energy Inc.	100	Delaware
XTO Offshore Inc.	100	Delaware

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.

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the following Exxon Mobil Corporation Registration Statements on:

Form S-3	(No. 33-8922)	—	Guaranteed Debt Securities of SeaRiver Maritime Financial Holdings, Inc. (formerly Exxon Shipping Company);
Form S-3	(No. 333-167787)	—	XTO Energy Inc. 2004 Stock Incentive Plan;
Form S-8	(Nos. 333-101175, 333-38917, 33-51107 and 333-75659)	—	1993 Incentive Program of Exxon Mobil Corporation;
Form S-8	(Nos. 333-145188 and 333-110494)	—	2003 Incentive Program of Exxon Mobil Corporation;
Form S-8	(Nos. 333-72955 and 333-166576)	—	ExxonMobil Savings Plan;
Form S-8	(No. 333-117980)	—	2004 Non-employee Director Restricted Stock Plan;
Form S-8	(No. 333-164620)	—	Post-effective amendment no. 1 on Form S-8 to Form S-4 relating to XTO Energy Inc. 1998 Stock Incentive Plan and 2004 Incentive Plan

of our report dated February 25, 2011, relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K/A.

/S/ PRICEWATERHOUSECOOPERS LLP

Dallas, Texas
February 28, 2011

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, 2011

/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, 2011

/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, 2011

/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, 2010, 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, 2011

/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, 2010, 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, 2011

/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, 2010, 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, 2011

/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.

Exxon Mobil Corporation
5959 Las Colinas Boulevard
Irving, Texas 75039-2298

February 28, 2011

Exxon Mobil Corporation
2010 Annual Report on Form 10-K/A
(Amendment No. 1)

Securities and Exchange Commission
100 F Street N.E.
Washington, D.C. 20549

Attention: EDGAR Document Control

Dear Sirs:

Transmitted with this cover note is the Amendment No. 1 to the Annual Report on Form 10-K filed on February 25, 2011.

Sincerely,

/s/ BEVERLEY A. BABCOCK

Beverley A. Babcock
Assistant Controller

Attachments