

EXXON MOBIL CORP
Form 10-K
February 26, 2014

2013

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549**

FORM 10-K

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

For the fiscal year ended December 31, 2013

or

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

For the transition period from to

Commission File Number 1-2256

EXXON MOBIL CORPORATION

(Exact name of registrant as specified in its charter)

NEW JERSEY
(State or other jurisdiction of

incorporation or organization)

13-5409005
(I.R.S. Employer

Identification Number)

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298

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(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 (4,321,238,544 shares outstanding at January 31, 2014)	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 No

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large accelerated filer Accelerated filer

Non-accelerated filer Smaller reporting company

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

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of \$90.35 on the New York Stock Exchange composite tape, was in excess of \$397 billion.

Documents Incorporated by Reference: Proxy Statement for the 2014 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2013
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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*, *Mobil* or *XTO*. For convenience and simplicity, in this report the terms *ExxonMobil*, *Exxon*, *Esso*, *Mobil* and *XTO*, as well as terms like *Corporation*, *Company*, *our*, *we* and *its*, are sometimes used as abbreviated references to specific affiliates or groups of affiliates. The precise meaning depends on the context in question.

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on 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. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2013 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were \$6.0 billion, of which \$3.5 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to remain in this range in 2014 and 2015 (with capital expenditures approximately 45 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 18: 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 2013. For technology licensed to third parties, revenues totaled approximately \$195 million in 2013. 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 75.0 thousand, 76.9 thousand and 82.1 thousand at years ended 2013, 2012 and 2011, 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 9.8 thousand, 11.1 thousand and 17.0 thousand at years ended 2013, 2012 and 2011, 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, periods of civil unrest, government austerity programs, or currency exchange rate fluctuations, can also impact the demand for energy and petrochemicals. Sovereign debt downgrades, defaults, inability to access debt markets due to credit or legal constraints, liquidity crises, the breakup or restructuring of fiscal, monetary, or political systems such as the European Union, and other events or 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 interest rates, inflation, currency exchange rates, 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;
•	adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information, or that could cause us to violate the non-disclosure laws of other countries; and
•	government actions to cancel contracts, re-denominate the official currency, renounce or default on obligations, renegotiate terms unilaterally, or expropriate assets.

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, especially in countries such as the United States in which very large and unpredictable punitive damage awards may occur, or by government enforcement proceedings alleging non-compliance with applicable laws or regulations.

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 shift 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 to support alternative energy sources or are mandating the use of specific fuels or technologies. 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 liquid products from algae and biomass that can be further converted to transportation fuels. 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 energy products of the future in a cost-competitive manner. 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 co-venturers 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 and within budget.

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.

The term “project” as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

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, regular reappraisal of our asset portfolio, and the recruitment, development and retention of high caliber employees.

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, to control effectively our business activities and to minimize the potential for human error. 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.

Business risks also include the risk of cybersecurity breaches. If our systems for protecting against cybersecurity risks prove not to be sufficient, ExxonMobil could be adversely affected such as by having its business systems compromised, its proprietary information altered, lost or stolen, or its business operations disrupted.

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.

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 2013**

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, 2013, that would cause a significant change in the estimated proved reserves as of that date.

			Crude	Natural Gas		Synthetic	Natural	Oil-Equivalent
			Oil	Liquids	Bitumen	Oil	Gas	Basis
			<i>(million bbls)</i>	<i>(million bbls)</i>	<i>(million bbls)</i>	<i>(million bbls)</i>	<i>(billion cubic ft)</i>	<i>(million bbls)</i>
Proved Reserves								
Developed								
Consolidated Subsidiaries								
		United States	1,212	257	-	-	14,655	3,912
		Canada/South America (1)	111	15	1,810	579	664	2,626
		Europe	210	39	-	-	2,189	613
		Africa	765	180	-	-	779	1,075
		Asia	1,525	138	-	-	5,241	2,537
		Australia/Oceania	56	49	-	-	969	266
		Total Consolidated	3,879	678	1,810	579	24,497	11,029
Equity Companies								
		United States	258	10	-	-	197	301
		Europe	27	-	-	-	6,852	1,169
		Asia	902	390	-	-	17,288	4,173
		Total Equity Company	1,187	400	-	-	24,337	5,643
		Total Developed	5,066	1,078	1,810	579	48,834	16,672

Undeveloped							
	Consolidated Subsidiaries						
	United States	796	272	-	-	11,365	2,962
	Canada/South America (1)	173	4	1,820	-	571	2,092
	Europe	35	16	-	-	621	155
	Africa	428	21	-	-	88	464
	Asia	638	-	-	-	493	720
	Australia/Oceania	99	32	-	-	6,546	1,222
	Total Consolidated	2,169	345	1,820	-	19,684	7,615
	Equity Companies						
	United States	72	5	-	-	84	91
	Europe	1	-	-	-	2,032	340
	Asia	243	51	-	-	1,226	498
	Total Equity Company	316	56	-	-	3,342	929
	Total Undeveloped	2,485	401	1,820	-	23,026	8,544
	Total Proved Reserves	7,551	1,479	3,630	579	71,860	25,216

(1) South America includes proved developed reserves of 0.2 million barrels of crude oil and natural gas liquids and 44 billion cubic feet of natural gas and proved undeveloped reserves of 0.1 million barrels of crude oil and natural gas liquids and 10 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 2014-2018. 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 and reservoir 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 2013

Additions to ExxonMobil's proved reserves in 2013 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. 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 Global Reserves group that provides technical oversight and 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 Manager of the Global Reserves group has more than 30 years of experience in reservoir engineering and reserves assessment and has a degree in Engineering. He is an active member of the Society of Petroleum Engineers (SPE) and previously served on the SPE Oil and Gas Reserves Committee. 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 individuals who hold advanced degrees in either Engineering or Geology. Several members of the group hold professional registrations in their field of expertise, and members have served on the SPE Oil and Gas Reserves Committee.

The Global Reserves group maintains a central database containing the official company reserves estimates. Appropriate controls, including limitations on database access and update capabilities, are in place to ensure data integrity within this central 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 Global Reserves 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 2013, approximately 8.5 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 34 percent of the 25.2 GOEB reported in proved reserves. This compares to the 9.9 GOEB of proved undeveloped reserves reported at the end of 2012. The net decrease is primarily due to project startups in Canada and Kazakhstan. During the year, ExxonMobil conducted development activities in over 100 fields that resulted in the transfer of approximately 1.9 GOEB from proved undeveloped to proved developed reserves by year-end. The largest transfers were related to Kearn Initial Development startup and new pad steam injection in the Cold Lake field in Canada, Kashagan field startup in Kazakhstan and the Groningen compression assessment in the Netherlands.

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 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 2013, discoveries and extensions related to new projects added approximately 0.7 GOEB of proved undeveloped reserves. The largest of these additions were related to planned drilling in the United States and Upper Zakum field expansion in Abu Dhabi. Overall, investments of \$25.3 billion were made by the Corporation during 2013 to progress the development of reported proved undeveloped reserves, including \$22.7 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 support infrastructure and other related facilities that were undertaken to progress the development of proved undeveloped reserves. These investments represented 66 percent of the \$38.2 billion in total reported Upstream capital and exploration expenditures.

Proved undeveloped reserves in Australia, Papua New Guinea, the United States, Kazakhstan, Nigeria, and the Netherlands have remained undeveloped for five years or more primarily due to constraints on the capacity of infrastructure, the pace of co-venturer/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, regulatory approvals, and significant changes in long-term oil and gas price levels. Of the proved undeveloped reserves that have been reported for five or more years, 91 percent are contained in the aforementioned countries. The largest of these is related to LNG/Gas projects in Australia and Papua New Guinea, where construction of the initial development is under way. In Kazakhstan, the proved undeveloped reserves are related to the remainder of the initial development of the offshore Kashagan field which is included in the North Caspian Production Sharing Agreement and the Tengizchevroil joint venture which includes a production license in the Tengiz – Korolev field complex. The Tengizchevroil joint venture is producing, and proved undeveloped reserves will continue to move to proved developed as approved development phases progress. In the Netherlands, the Groningen gas field has proved undeveloped reserves reported that are related to installation of future stages of compression. These reserves will move to proved developed when the additional stages of compression are installed to maintain field delivery pressure.

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.

				2013		2012		2011	
				<i>(thousands of barrels daily)</i>					
Crude oil and natural gas liquids production				Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries									
	United States			283	85	274	81	280	77
	Canada/South America (1)			57	10	49	10	53	12
	Europe			157	27	170	33	219	46
	Africa			451	18	472	15	491	17
	Asia			313	30	319	43	329	54
	Australia/Oceania			29	19	32	18	34	17
		Total Consolidated Subsidiaries		1,290	189	1,316	200	1,406	223
Equity Companies									
	United States			61	2	61	2	65	1
	Europe			6	-	4	-	5	-
	Asia			373	68	345	65	358	67
		Total Equity Companies		440	70	410	67	428	68
Total crude oil and natural gas liquids production				1,730	259	1,726	267	1,834	291
Bitumen production									
Consolidated Subsidiaries									
	Canada/South America			148		123		120	
Synthetic oil production									
Consolidated Subsidiaries									
	Canada/South America			65		69		67	
Total liquids production				2,202		2,185		2,312	
				<i>(millions of cubic feet daily)</i>					
Natural gas production available for sale									

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.

			United	Canada/					Australia/	
			States	S. America	Europe	Africa	Asia	Oceania	Total	
During 2013			<i>(dollars per unit)</i>							
Consolidated Subsidiaries										
	Average production prices									
		Crude oil, per barrel	93.56	98.91	106.75	108.73	106.18	107.92	104.13	
		NGL, per barrel	44.30	44.96	65.36	75.24	40.83	59.55	51.12	
		Natural gas, per thousand cubic feet	2.99	2.80	10.07	2.79	4.10	4.20	4.60	
		Bitumen, per barrel	-	59.63	-	-	-	-	59.63	
		Synthetic oil, per barrel	-	93.96	-	-	-	-	93.96	
	Average production costs, per oil-equivalent barrel - total		12.02	32.02	19.57	13.95	8.95	16.81	15.42	
	Average production costs, per barrel - bitumen		-	34.30	-	-	-	-	34.30	
	Average production costs, per barrel - synthetic oil		-	50.94	-	-	-	-	50.94	
Equity Companies										
	Average production prices									
		Crude oil, per barrel	102.24	-	99.26	-	103.96	-	103.66	
		NGL, per barrel	42.02	-	-	-	70.90	-	69.96	
		Natural gas, per thousand cubic feet	4.37	-	9.28	-	10.19	-	9.82	
	Average production costs, per oil-equivalent barrel - total		22.77	-	3.79	-	1.87	-	3.36	
Total										

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	Average production prices									
	Crude oil, per barrel	95.11	98.91	106.49	108.73	104.98	107.92	104.01		
	NGL, per barrel	44.24	44.96	65.36	75.24	61.64	59.55	56.26		
	Natural gas, per thousand cubic feet	3.00	2.80	9.59	2.79	8.53	4.20	6.86		
	Bitumen, per barrel	-	59.63	-	-	-	-	59.63		
	Synthetic oil, per barrel	-	93.96	-	-	-	-	93.96		
	Average production costs, per oil-equivalent barrel - total	12.72	32.02	12.42	13.95	4.41	16.81	11.48		
	Average production costs, per barrel - bitumen	-	34.30	-	-	-	-	34.30		
	Average production costs, per barrel - synthetic oil	-	50.94	-	-	-	-	50.94		
During 2012										
Consolidated Subsidiaries										
	Average production prices									
	Crude oil, per barrel	94.71	98.67	110.91	111.19	109.95	112.12	107.05		
	NGL, per barrel	50.32	57.84	68.08	76.63	43.65	56.85	54.71		
	Natural gas, per thousand cubic feet	2.15	1.98	8.92	2.77	3.91	4.39	3.90		
	Bitumen, per barrel	-	58.91	-	-	-	-	58.91		
	Synthetic oil, per barrel	-	92.77	-	-	-	-	92.77		
	Average production costs, per oil-equivalent barrel - total	11.14	26.94	15.06	13.35	7.27	12.11	13.02		
	Average production costs, per barrel - bitumen	-	23.71	-	-	-	-	23.71		
	Average production costs, per barrel - synthetic oil	-	47.45	-	-	-	-	47.45		
Equity Companies										
	Average production prices									
	Crude oil, per barrel	105.02	-	104.59	-	106.59	-	106.33		
	NGL, per barrel	58.38	-	-	-	75.24	-	74.87		
	Natural gas, per thousand cubic	3.22	-	9.66	-	9.38	-	9.48		

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		feet								
		Average production costs, per oil-equivalent barrel - total	20.15	-	3.36	-	1.43	-	2.80	
Total										
		Average production prices								
		Crude oil, per barrel	96.60	98.67	110.74	111.19	108.22	112.12	106.88	
		NGL, per barrel	50.46	57.84	68.08	76.63	62.61	56.85	59.74	
		Natural gas, per thousand cubic feet	2.15	1.98	9.33	2.77	7.64	4.39	6.11	
		Bitumen, per barrel	-	58.91	-	-	-	-	58.91	
		Synthetic oil, per barrel	-	92.77	-	-	-	-	92.77	
		Average production costs, per oil-equivalent barrel - total	11.68	26.94	10.34	13.35	3.74	12.11	9.91	
		Average production costs, per barrel - bitumen	-	23.71	-	-	-	-	23.71	
		Average production costs, per barrel - synthetic oil	-	47.45	-	-	-	-	47.45	

				United	Canada/					Australia/	
				States	S. America	Europe	Africa	Asia	Oceania	Total	
During 2011			<i>(dollars per unit)</i>								
Consolidated Subsidiaries											
	Average production prices										
		Crude oil, per barrel	98.33	104.59	109.48	110.84	107.64	115.55	107.25		
		NGL, per barrel	62.48	65.71	66.80	78.20	44.16	59.44	60.15		
		Natural gas, per thousand cubic feet	3.45	3.29	9.32	2.83	3.37	3.98	4.65		
		Bitumen, per barrel	-	64.65	-	-	-	-	64.65		
		Synthetic oil, per barrel	-	102.80	-	-	-	-	102.80		
		Average production costs, per oil-equivalent barrel - total	11.14	23.58	13.58	14.04	6.58	12.85	12.33		
		Average production costs, per barrel - bitumen	-	19.80	-	-	-	-	19.80		
		Average production costs, per barrel - synthetic oil	-	47.68	-	-	-	-	47.68		
Equity Companies											
	Average production prices										
		Crude oil, per barrel	105.00	-	103.23	-	105.87	-	105.71		
		NGL, per barrel	77.84	-	-	-	69.65	-	69.82		
		Natural gas, per thousand cubic feet	5.08	-	8.61	-	7.78	-	8.08		
		Average production costs, per oil-equivalent barrel - total	19.96	-	2.92	-	1.09	-	2.45		
Total											
	Average production prices										
		Crude oil, per barrel	99.57	104.59	109.33	110.84	106.72	115.55	106.89		
		NGL, per barrel	62.75	65.71	66.80	78.20	58.33	59.44	62.42		
		Natural gas, per thousand cubic	3.45	3.29	8.96	2.83	6.14	3.98	5.93		

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		feet										
		Bitumen, per barrel	-	64.65	-	-	-	-	-	-	-	64.65
		Synthetic oil, per barrel	-	102.80	-	-	-	-	-	-	-	102.80
		Average production costs, per oil-equivalent barrel - total	11.68	23.58	9.85	14.04	3.41	12.85	9.45			
		Average production costs, per barrel - bitumen	-	19.80	-	-	-	-	-	-	-	19.80
		Average production costs, per barrel - synthetic oil	-	47.68	-	-	-	-	-	-	-	47.68

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.

4. Drilling and Other Exploratory and Development Activities**A. Number of Net Productive and Dry Wells Drilled**

				2013	2012	2011
Net Productive Exploratory Wells Drilled						
Consolidated Subsidiaries						
		United States		8	7	12
		Canada/South America		4	2	6
		Europe		-	1	1
		Africa		2	2	1
		Asia		-	1	2
		Australia/Oceania		-	2	1
			Total Consolidated Subsidiaries	14	15	23
Equity Companies						
		United States		-	-	1
		Europe		1	1	1
		Asia		1	-	-
			Total Equity Companies	2	1	2
Total productive exploratory wells drilled				16	16	25
Net Dry Exploratory Wells Drilled						
Consolidated Subsidiaries						
		United States		2	2	2
		Canada/South America		4	-	-
		Europe		1	2	4
		Africa		-	-	-
		Asia		-	2	5
		Australia/Oceania		-	1	-
			Total Consolidated Subsidiaries	7	7	11
Equity Companies						
		United States		1	-	-
		Europe		-	1	-
		Asia		-	-	-
			Total Equity Companies	1	1	-
Total dry exploratory wells drilled				8	8	11

				2013	2012	2011
Net Productive Development Wells Drilled						
Consolidated Subsidiaries						
		United States		755	867	1,069
		Canada/South America		201	73	154
		Europe		13	10	7
		Africa		33	39	44
		Asia		30	28	30
		Australia/Oceania		3	-	-
		Total Consolidated Subsidiaries		1,035	1,017	1,304
Equity Companies						
		United States		328	282	236
		Europe		2	4	10
		Asia		8	7	4
		Total Equity Companies		338	293	250
Total productive development wells drilled				1,373	1,310	1,554
Net Dry Development Wells Drilled						
Consolidated Subsidiaries						
		United States		5	5	14
		Canada/South America		-	-	-
		Europe		2	1	1
		Africa		-	-	-
		Asia		-	2	1
		Australia/Oceania		-	-	-
		Total Consolidated Subsidiaries		7	8	16
Equity Companies						
		United States		-	-	-
		Europe		1	-	-
		Asia		-	-	-
		Total Equity Companies		1	-	-
Total dry development wells drilled				8	8	16
Total number of net wells drilled				1,405	1,342	1,606

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 2013, the company's share of net production of synthetic crude oil was about 65 thousand barrels per day and share of net acreage was 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. Bitumen is extracted from oil sands produced from open-pit mining operations, and processed through a bitumen extraction and froth treatment train. The product, a blend of bitumen and diluent, is shipped to our refineries and to other third parties. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation by pipeline. Production from the initial development began in April 2013 and production ramp-up continued throughout the remainder of the year. During 2013, average net production at Kearl was 21 thousand barrels per day. The Kearl Expansion project was 72 percent complete at the end of 2013.

5. Present Activities

A. Wells Drilling

			Year-End 2013			Year-End 2012		
			Gross	Net	Gross	Net	Gross	Net
Wells Drilling								
Consolidated Subsidiaries								
	United States		1,199	480	1,099	503		
	Canada/South America		107	95	138	118		
	Europe		29	10	26	10		
	Africa		38	11	33	10		
	Asia		112	32	108	61		
	Australia/Oceania		18	5	23	6		
		Total Consolidated Subsidiaries	1,503	633	1,427	708		
Equity Companies								
	United States		9	4	17	4		

	Europe	8	3	9	3
	Asia	11	1	19	2
	Total Equity Companies	28	8	45	9
Total gross and net wells drilling		1,531	641	1,472	717

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2013 acreage holdings totaled 15.1 million net acres, of which 2.0 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska.

During 2013, 1080.3 net exploration and development wells were completed in the inland lower 48 states. Development activities focused on the Bakken oil play in North Dakota and Montana, the San Joaquin Basin of California, the Woodford and Caney Shales in the Ardmore, Marietta and Arkoma basins of Oklahoma, the Permian Basin of West Texas and New Mexico, the Marcellus Shale of Pennsylvania and West Virginia, the Haynesville Shale of Texas and Louisiana, the Barnett Shale of North Texas, and the Fayetteville Shale of Arkansas.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2013 was 1.9 million acres. A total of 2.5 net exploration and development wells were completed during the year. Development activities continued on the deepwater Hadrian South project and the non-operated Lucius project. The Heidelberg and Julia Phase 1 projects were funded in 2013.

Participation in Alaska production and development continued with a total of 17.1 net development wells completed. Development activities continued on the Point Thomson project.

CANADA / SOUTH AMERICA

Canada

Oil and Gas Operations: ExxonMobil's year-end 2013 acreage holdings totaled 5.6 million net acres, of which 1.0 million net acres were offshore. A total of 86.2 net exploration and development wells were completed during the year. Celtic Exploration Ltd. was acquired in 2013.

In Situ Bitumen Operations: ExxonMobil's year-end 2013 in situ bitumen acreage holdings totaled 0.7 million net onshore acres. A total of 120.0 net development wells were completed during the year. In 2013, ExxonMobil acquired an interest in the Clyden oil sands lease.

Argentina

ExxonMobil's net acreage totaled 0.9 million onshore acres at year-end 2013, and there were 2.0 net exploration and development wells completed during the year.

Venezuela

ExxonMobil's acreage holdings and assets were expropriated in 2007. Refer to the relevant portion of "Note 16: Litigation and Other Contingencies" of the Financial Section of this report for additional information.

EUROPE

Germany

A total of 4.9 million net onshore acres and 0.1 million net offshore acres were held by ExxonMobil at year-end 2013, with 5.3 net exploration and development wells completed during the year.

Netherlands

ExxonMobil's net interest in licenses totaled approximately 1.5 million acres at year-end 2013, of which 1.2 million acres are onshore. A total of 4.2 net exploration and development wells were completed during the year.

Norway

ExxonMobil's net interest in licenses at year-end 2013 totaled approximately 0.7 million acres, all offshore. A total of 7.5 net exploration and development wells were completed in 2013.

United Kingdom

ExxonMobil's net interest in licenses at year-end 2013 totaled approximately 0.4 million acres, all offshore. A total of 2.7 net development wells were completed during the year.

AFRICA

Angola

ExxonMobil's year-end 2013 acreage holdings totaled 0.4 million net offshore acres and 3.4 net development wells were completed during the year. On Block 15, project activities are under way at Kizomba Satellites Phase 2. On the non-operated Block 17, work continued on the Cravo-Lirio-Orquidea-Violeta project.

Chad

ExxonMobil's net year-end 2013 acreage holdings consisted of 46 thousand onshore acres, with 22.0 net development wells completed during the year.

Equatorial Guinea

ExxonMobil's acreage totaled 0.1 million net offshore acres at year-end 2013.

Nigeria

ExxonMobil's net acreage totaled 0.9 million offshore acres at year-end 2013, with 8.2 net exploration and development wells completed during the year. In 2013, ExxonMobil continued development drilling on the Satellite Field Development Phase 1 and the deepwater Usan projects. The Erha North Phase 2 deepwater project was funded in 2013.

ASIA

Azerbaijan

At year-end 2013, ExxonMobil's net acreage totaled 9 thousand offshore acres. A total of 0.7 net development wells were completed during the year. Work continued on the Chirag Oil project.

Indonesia

At year-end 2013, ExxonMobil had 2.3 million net acres, 1.3 million net acres offshore and 1.0 million net acres onshore. There was 0.4 net exploration well completed during the year.

Iraq

At year-end 2013, ExxonMobil's onshore acreage was 0.9 million net acres. A total of 23.2 net development wells were completed at the West Qurna Phase I oil field during the year. Field rehabilitation activities continued during 2013, and across the life of this project will include drilling of new wells, working over of existing wells, and optimization and debottlenecking of existing facilities. ExxonMobil sold a partial interest in West Qurna Phase I in 2013. In the Kurdistan Region of Iraq, ExxonMobil initiated a seismic program and exploration drilling in 2013.

Kazakhstan

ExxonMobil's net acreage totaled 0.1 million acres onshore and 0.2 million acres offshore at year-end 2013. A total of 1.3 net development wells were completed during 2013. Working with our partners, construction of the initial phase of the Kashagan field continued, and the project started up in 2013.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.4 million net acres offshore at year-end 2013. During the year, a total of 5.0 net development wells were completed. Development activities continued on the Tapis and Damar projects and the Telok project started up in 2013.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil's net acreage totaled 65 thousand acres offshore at year-end 2013. During the year, a total of 0.7 net development wells were completed. ExxonMobil participated in 61.8 million tonnes per year gross liquefied natural gas capacity and 2.0 billion cubic feet per day of flowing gas capacity at year end. Development activities continued on the Barzan project.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 10 thousand acres onshore at year-end 2013.

Russia

ExxonMobil's net acreage holdings in Sakhalin at year-end 2013 were 85 thousand acres, all offshore. A total of 0.9 net development wells were completed. Development activities continued on the Arkutun-Dagi project during 2013.

At year-end 2013, ExxonMobil's net acreage in the Rosneft joint venture agreements for the Kara and Black Seas was 11.3 million acres, all offshore. ExxonMobil and Rosneft formed a joint venture to evaluate the development of tight-oil reserves in western Siberia in 2013.

Thailand

ExxonMobil's net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2013.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2013. The Upper Zakum 750 project was funded in 2013.

ExxonMobil's net acreage in the Abu Dhabi onshore oil concession was 0.5 million acres at year-end 2013, of which 0.4 million acres are onshore. During the year, a total of 6.7 net exploration and development wells were completed. The onshore oil concession expired in January 2014.

AUSTRALIA / OCEANIA

Australia

ExxonMobil's year-end 2013 acreage holdings totaled 1.7 million net acres, of which 1.6 million net acres were offshore. During the year, a total of 1.9 net exploration and development wells were completed. The Kipper Tuna and Turrum projects started up during 2013.

Project construction activity for the co-venturer operated Gorgon liquefied natural gas (LNG) project progressed in 2013. The project consists of a subsea infrastructure for offshore production and transportation of the gas, and a 15.6 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 1.1 million net onshore acres were held by ExxonMobil at year-end 2013, with 1.3 net development wells completed during the year. Work continued on the Papua New Guinea (PNG) LNG project. The project consists of conditioning facilities in the southern PNG Highlands, a 6.9 million tonnes per year LNG facility near Port Moresby and approximately 434 miles of onshore and offshore pipelines.

WORLDWIDE EXPLORATION

At year-end 2013, 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 29.1 million net acres were held at year-end 2013, and 1.4 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 2,800 billion cubic feet of natural gas for the period from 2014 through 2016. 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 2013				Year-End 2012			
			Oil		Gas		Oil		Gas	
			Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells										
Consolidated Subsidiaries										
		United States	23,395	8,487	38,392	23,839	22,690	8,155	39,720	24,197
		Canada/South America	5,486	4,990	4,478	1,762	5,283	4,825	4,271	1,584
		Europe	1,254	352	649	269	1,255	346	622	258
		Africa	1,186	472	16	6	1,231	491	11	4
		Asia	756	270	207	151	792	370	204	150
		Australia/Oceania	661	147	38	19	676	152	40	20
		Total Consolidated Subsidiaries	32,738	14,718	43,780	26,046	31,927	14,339	44,868	26,213
Equity Companies										
		United States	14,362	5,529	4,369	496	12,777	5,286	2,138	120
		Europe	49	17	555	173	71	27	585	185
		Asia	1,329	143	122	29	1,200	129	121	29
		Total Equity Companies	15,740	5,689	5,046	698	14,048	5,442	2,844	334
Total gross and net productive wells			48,478	20,407	48,826	26,744	45,975	19,781	47,712	26,547

There were 37,661 gross and 31,823 net operated wells at year-end 2013 and 37,228 gross and 31,264 net operated wells at year-end 2012. The number of wells with multiple completions was 1,531 gross in 2013 and 1,647 gross in 2012.

Note: Year-end 2012 well counts for gross and net gas wells in Canada/South America were restated.

B. Gross and Net Developed Acreage

				Year-End 2013		Year-End 2012	
				Gross	Net	Gross	Net
				<i>(thousands of acres)</i>			
Gross and Net Developed Acreage							
Consolidated Subsidiaries							
		United States		16,504	10,061	16,444	10,164
		Canada/South America (1)		4,421	2,041	4,545	1,940
		Europe		3,355	1,511	3,382	1,515
		Africa		2,105	780	2,105	780
		Asia		1,828	557	1,322	525
		Australia/Oceania		2,123	758	2,018	719
		Total Consolidated Subsidiaries		30,336	15,708	29,816	15,643
Equity Companies							
		United States		968	241	496	202
		Europe		4,341	1,356	4,344	1,357
		Asia		5,731	640	5,731	640
		Total Equity Companies		11,040	2,237	10,571	2,199
Total gross and net developed acreage				41,376	17,945	40,387	17,842

(1) Includes developed acreage in South America of 214 gross and 109 net thousands of acres for 2013 and 618 gross and 202 net thousand acres for 2012.

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 2013		Year-End 2012	
				Gross	Net	Gross	Net
				<i>(thousands of acres)</i>			
Gross and Net Undeveloped Acreage							
Consolidated Subsidiaries							
		United States		7,645	4,722	8,517	5,077
		Canada/South America (1)		16,319	9,232	16,669	8,700
		Europe		13,461	6,585	35,928	16,123
		Africa		20,877	13,446	12,005	7,707
		Asia		18,639	13,979	24,346	20,239
		Australia/Oceania		7,144	1,991	7,460	1,991

		Total Consolidated Subsidiaries	84,085	49,955	104,925	59,837
	Equity Companies					
		United States	363	121	351	108
		Europe	-	-	-	-
		Asia	34,147	11,352	73	5
		Total Equity Companies	34,510	11,473	424	113
	Total gross and net undeveloped acreage		118,595	61,428	105,349	59,950

(1) Includes undeveloped acreage in South America of 8,795 gross and 4,674 net thousands of acres for 2013 and 8,412 gross and 4,484 net thousands of acres for 2012.

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 licenses or leases in onshore areas are acquired for varying periods of time with renewals or extensions possible. These licenses or leases entitle the holder to continue existing licenses or leases upon completing specified work. In general, these license and lease agreements are held as long as there is production on the licenses and leases. Exploration licenses in offshore eastern Canada and the Beaufort Sea are held by work commitments of various amounts and rentals. They are valid for a maximum term of nine years. Production licenses in the offshore are valid for 25 years, with rights of extension for continued production. Significant discovery licenses in the offshore, relating to currently undeveloped discoveries, do not have a definite term.

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 concession terms of the exploration permits granted by Neuquen Province are up to six years for the initial exploration period, up to four years for the second exploration period and up to three years for the third exploration period depending on the classification of the area. An extension after the third exploration period is possible for up to one 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.

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 license and are based on 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

Acreege 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 10 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. Under the Hydrocarbons Law enacted in 2006, 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 (PSC), negotiated with BPMIGAS, a government agency established in 2002 to manage upstream oil and gas activities. In 2012, Indonesia's Constitutional Court ruled certain articles of law relating to BPMIGAS to be unconstitutional, but stated that all existing PSCs signed with BPMIGAS should remain in force until their expiry, and the functions and duties previously performed by BPMIGAS are to be carried out by the relevant Ministry of the Government of Indonesia until the promulgation of a new oil and gas law. The current PSCs have an exploration period of six years, which can be extended up to 10 years, and an exploitation period of 20 years. PSCs generally require the contractor to relinquish 10 percent to 20 percent of the contract area after three years and generally allow the contractor to retain no more than 50 percent to 80 percent of the original contract area after six years, depending on the acreage and terms.

Iraq

Development and production activities in the state-owned oil and gas fields are governed by contracts with regional oil companies of the Iraqi Ministry of Oil. An ExxonMobil affiliate entered into a contract with South Oil Company of the Iraqi Ministry of Oil 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 five years. The contract provides for cost recovery plus per-barrel fees for incremental production above specified levels.

Exploration and production activities in the Kurdistan Region of Iraq are governed by production sharing contracts negotiated with the regional government of Kurdistan in 2011. The exploration term is for five years with the possibility of two-year extensions. The production period is 20 years with the right to extend for five 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 was 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 expired on March 31, 2012, the producing fields covered by the existing PSC automatically became 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 Sakhalin 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 ten-year increments as specified in the PSA.

Exploration and production activities in the Kara and Black Seas are governed by joint venture agreements concluded with Rosneft in 2013 that cover certain of Rosneft's offshore licenses. The Kara Sea licenses extend through 2040 and include an exploration period through 2020, development plan submission within eight years of a discovery and development activities within five years of plan approval. The Black Sea exploration license extends through 2017 and a discovery is the basis for obtaining a license for production.

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 were governed by a 75-year oil concession agreement executed in 1939, which expired in January 2014. An interest in the development and production activities of the Upper Zakum field, a major offshore field, was acquired effective as of January 2006, for a term expiring March 2026, and in 2013 the governing agreements were extended to 2041.

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.

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 2013 (1)

			ExxonMobil	ExxonMobil
			Share KBD	Interest %
			(2)	
United States				
	Torrance	California	150	100
	Joliet	Illinois	238	100
	Baton Rouge	Louisiana	502	100
	Baytown	Texas	561	100
	Beaumont	Texas	345	100
	Other (2 refineries)		155	
		Total United States	1,951	
Canada				
	Strathcona	Alberta	189	69.6
	Nanticoke	Ontario	113	69.6
	Sarnia	Ontario	119	69.6
		Total Canada	421	
Europe				
	Antwerp	Belgium	307	100
	Fos-sur-Mer	France	133	82.9
	Gravenchon	France	236	82.9
	Karlsruhe	Germany	78	25
	Augusta	Italy	198	100
	Trecate	Italy	127	75.5
	Rotterdam	Netherlands	191	100
	Slagen	Norway	116	100
	Fawley	United Kingdom	260	100
		Total Europe	1,646	
Asia Pacific				
	Jurong/PAC	Singapore	592	100
	Sriracha	Thailand	167	66
	Other (7 refineries)		297	

		Total Asia Pacific		1,056			
Other Non-U.S.							
	Yanbu	Saudi Arabia		200		50	
	Laffan	Qatar		15		10	
	Fort-de-France	Martinique		2		14.5	
		Total Other Non-U.S.		217			
Total Worldwide				5,291			

(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 through our *Exxon*, *Esso* and *Mobil* brands.

Retail Sites At Year-End 2013

	United States		
	Owned/leased		-
	Distributors/resellers		9,196
		Total United States	9,196
	Canada		
	Owned/leased		472
	Distributors/resellers		1,259
		Total Canada	1,731
	Europe		
	Owned/leased		3,445
	Distributors/resellers		2,812
		Total Europe	6,257
	Asia Pacific		
	Owned/leased		666
	Distributors/resellers		313
		Total Asia Pacific	979
	Latin America		
	Owned/leased		53
	Distributors/resellers		705
		Total Latin America	758
	Middle East/Africa		
	Owned/leased		436
	Distributors/resellers		197
		Total Middle East/Africa	633
	Worldwide		
	Owned/leased		5,072
	Distributors/resellers		14,482
		Total Worldwide	19,554

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 2013 (1)(2)

			Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest %
North America							
	Baton Rouge	Louisiana	1.0	1.3	0.4	-	100
	Baytown	Texas	2.2	-	0.7	0.6	100
	Beaumont	Texas	0.9	1.0	-	0.3	100
	Mont Belvieu	Texas	-	1.0	-	-	100
	Sarnia	Ontario	0.3	0.5	-	-	69.6
	Total North America		4.4	3.8	1.1	0.9	
Europe							
	Antwerp	Belgium	-	0.4	-	-	100
	Fife	United Kingdom	0.4	-	-	-	50
	Meerhout	Belgium	-	0.5	-	-	100
	Gravenchon	France	0.4	0.4	0.3	-	100
	Rotterdam	Netherlands	-	-	-	0.7	100
	Total Europe		0.8	1.3	0.3	0.7	
Middle East							
	Al Jubail	Saudi Arabia	0.6	0.7	-	-	50
	Yanbu	Saudi Arabia	1.0	0.7	0.2	-	50
	Total Middle East		1.6	1.4	0.2	-	
Asia Pacific							
	Fujian	China	0.2	0.2	0.1	0.2	25
	Kawasaki	Japan	0.1	-	-	-	22
	Singapore	Singapore	1.9	1.9	0.9	0.9	100
	Sriracha	Thailand	-	-	-	0.5	66
	Total Asia Pacific		2.2	2.1	1.0	1.6	
All Other			-	-	-	0.2	
Total Worldwide			9.0	8.6	2.6	3.4	

(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.

Item 3. Legal Proceedings

In November 2013, the Texas Commission on Environmental Quality (TCEQ) contacted Exxon Mobil Corporation (the "Corporation") concerning alleged violations of the Texas Clean Air Act, implementing regulations and the applicable new source review permit in connection with exceedances of volatile organic compound emissions from Tank 22 at the Corporation's King Ranch Gas Plant. TCEQ is seeking a civil penalty in excess of \$100,000 along with certain corrective action. The Corporation is working with TCEQ to resolve the matter.

Regarding the June 27, 2013, Administrative Consent Agreement between the North Dakota Department of Health (NDDOH) and XTO Energy Inc. (XTO) resolving the air enforcement matter previously reported in the Corporation's Forms 10-Q for the first and second quarters of 2013, pursuant to the terms of the Administrative Consent Agreement, during the fourth quarter of 2013, XTO provided the NDDOH with an updated list of well sites on newly acquired assets with air emission control issues. On November 12, 2013, XTO paid an additional penalty assessment of \$183,400 with respect to those sites.

Regarding the criminal charges filed against XTO by the Pennsylvania Attorney General's Office pertaining to XTO's Marquardt Well Site in Penn Township, Pennsylvania, reported most recently in the Corporation's Form 10-Q for the third quarter of 2013, on January 2, 2014, a Pennsylvania state magistrate ruled that the Attorney General's Office had presented sufficient evidence for the charges to proceed to trial in the Pennsylvania Court of Common Pleas. At the trial, XTO will have an opportunity to present its full defense to the charges, which it believes are unwarranted.

Regarding the settlement of matters between the Louisiana Department of Environmental Quality (LDEQ) and ExxonMobil Refining and Supply Company and ExxonMobil Chemical Company, both divisions of the Corporation, involving ExxonMobil facilities in Baton Rouge, Louisiana, last reported in the Corporation's Form 10-Q for the third quarter of 2013, during the fourth quarter of 2013, the public comment period on the proposed settlement ended, and the Louisiana Attorney General issued his concurrence with regard to the settlement terms. The parties executed the final documents in January 2014, thereby resolving the matters covered by the settlement. The settlement terms include payment of a \$300,000 penalty, an agreement to complete certain on-site improvement projects valued at \$1,000,000, Beneficial Environmental Projects valued at \$1,029,000 and a Stipulated Penalty Agreement to address any future environmental non-compliance.

On December 11, 2013, the TCEQ Commissioner's Court accepted and signed the Agreed Order settling the enforcement action, including a penalty of \$126,250, concerning emission events at ExxonMobil Oil Corporation's (EMOC) Beaumont Refinery previously reported in the Corporation's Forms 10-Q for the first and third quarters of 2013.

Regarding the complaint against EMOC filed by the Attorney General for the State of New York alleging contamination of soil and groundwater at a former Mobil petroleum terminal at Lighthouse Point in Ogdensburg, New York, previously reported in the Corporation's Form 10-Q for the third quarter of 2011, the parties reached a settlement agreement that was entered into the court record on November 14, 2013. On December 16, 2013, the parties signed the agreement, and EMOC made a payment to the State of \$8.05 million, pursuant to the agreement's terms.

Refer to the relevant portions of "Note 16: Litigation and Other Contingencies" of the Financial Section of this report for additional information on legal proceedings.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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

Rex W. Tillerson *Chairman of the Board*

Held current title since: January 1, 2006 Age: 61
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: 57
Mr. Mark W. Albers 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: 60
Mr. Michael J. Dolan became Senior Vice President of Exxon Mobil Corporation on April 1, 2008, a position he still holds as of this filing date.

Andrew P. Swiger *Senior Vice President*

Held current title since: April 1, 2009 Age: 57
Mr. Andrew P. Swiger 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: 62
Mr. S. Jack Balagia was Assistant General Counsel of Exxon Mobil Corporation April 1, 2004 – March 1, 2010. He became Vice President and General Counsel of Exxon Mobil Corporation on March 1, 2010, positions he still holds as of this filing date.

Randy J. Cleveland *President, XTO Energy Inc., a subsidiary of the Corporation*

Held current title since: June 1, 2013 Age: 52

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Mr. Randy J. Cleveland was Production Manager, U.S. Production, ExxonMobil Production Company April 1, 2006 – April 30, 2009. He was Planning & Commercial Manager, ExxonMobil Production Company May 1, 2009 – June 24, 2010. He was Vice President, XTO Integration, XTO Energy Inc. June 25, 2010 – January 31, 2012. He was Executive Vice President, XTO Energy Inc. February 1, 2012 – May 31, 2013. He became President of XTO Energy Inc. on June 1, 2013, a position he still holds as of this filing date.

William M. Colton

Vice President – Corporate Strategic Planning

Held current title since: February 1, 2009 Age: 60

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

Michael G. Cousins *Vice President*

Held current title since: March 1, 2013 Age: 53
 Mr. Michael G. Cousins was Planning Manager, ExxonMobil Exploration Company April 1, 2008 – May 31, 2009. He was Vice President, Asia Pacific/Middle East, ExxonMobil Exploration Company June 1, 2009 – March 31, 2012. He was Executive Assistant to the Chairman, Exxon Mobil Corporation April 1, 2012 – February 28, 2013. He became President of ExxonMobil Upstream Ventures and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Neil W. Duffin *President, ExxonMobil Development Company*

Held current title since: April 13, 2007 Age: 57
 Mr. Neil W. Duffin became President of ExxonMobil Development Company 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: 56
 Mr. Robert S. Franklin was Vice President, Europe/Russia/Caspian of ExxonMobil Production Company April 1, 2008 – May 1, 2009. He was Vice President of Exxon Mobil Corporation and President, ExxonMobil Upstream Ventures May 1, 2009 – February 28, 2013. He became President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Stephen M. Greenlee *Vice President*

Held current title since: September 1, 2010 Age: 56
 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: 56
 Mr. Alan J. Kelly became President of ExxonMobil Lubricants & Petroleum Specialties Company and Vice President of Exxon Mobil Corporation on December 1, 2007. On February 1, 2012, the businesses of ExxonMobil Lubricants & Petroleum Specialties Company and ExxonMobil Fuels Marketing Company were consolidated and Mr. Kelly became President of the combined ExxonMobil Fuels, Lubricants & Specialties Marketing Company and Vice President of Exxon Mobil Corporation, positions he still holds as of this filing date.

Patrick T. Mulva *Vice President and Controller*

Held current title since: February 1, 2002 (Vice President) Age: 62

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July 1, 2004 (Controller)

Mr. Patrick T. Mulva became Vice President of Exxon Mobil Corporation on February 1, 2002 and Controller of Exxon Mobil Corporation on July 1, 2004, positions he still holds as of this filing date.

Stephen D. Pryor

Vice President

Held current title since:

December 1, 2004

Age: 64

Mr. Stephen D. Pryor became Vice President of Exxon Mobil Corporation on December 1, 2004 and President of ExxonMobil Chemical Company 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: 57
Mr. David S. Rosenthal became Vice President – Investor Relations and Secretary of Exxon Mobil Corporation on October 1, 2008, positions he still holds as of this filing date.

Robert N. Schleckser *Vice President and Treasurer*

Held current title since: May 1, 2011 Age: 57
Mr. Robert N. Schleckser was Downstream Treasurer, Downstream Business Services May 1, 2005 – January 31, 2009. He was Assistant Treasurer of Exxon Mobil Corporation February 1, 2009 – April 30, 2011. He became Vice President and Treasurer of Exxon Mobil Corporation on May 1, 2011, 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: 52
Mr. James M. Spellings, Jr. was Associate General Tax Counsel of Exxon Mobil Corporation April 1, 2007 – March 1, 2010. He became Vice President and General Tax Counsel of Exxon Mobil Corporation 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: 59
Mr. Thomas R. Walters was Executive Vice President of ExxonMobil Development Company April 13, 2007 – April 1, 2009. He was President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation April 1, 2009 – February 28, 2013. He became President of ExxonMobil Production Company and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Darren W. Woods *Vice President*

Held current title since: August 1, 2012 Age: 49
Mr. Darren W. Woods was Director, Refining Europe/Africa/Middle East, ExxonMobil Refining & Supply Company February 1, 2008 – June 30, 2010. He was Vice President, Supply & Transportation, ExxonMobil Refining & Supply Company July 1, 2010 – July 31, 2012. He became President of ExxonMobil Refining & Supply Company and Vice President of Exxon Mobil Corporation on August 1, 2012, positions 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, 2013					
			Total Number of		
			Shares		
			Purchased as	Maximum	
			Part of Publicly	Number	
			Announced	of Shares that	
			Plans or	May	
			Programs	Yet Be	
			Programs	Purchased	
			Under the Plans	or	
			or	Programs	
Period	Total Number of	Average Price	Announced		
	Shares	Paid per	Plans or		
	Purchased	Share	Programs		
October 2013	12,589,049	87.12	12,589,049		
November 2013	13,152,312	93.69	13,152,312		
December 2013	10,025,720	97.08	10,025,720		
	Total	35,767,081	92.33	35,767,081	(See note 1)

Note 1 - On August 1, 2000, the Corporation announced its intention to resume purchases of shares of its common stock for the treasury both to offset shares issued in conjunction with company benefit plans and programs and to gradually reduce the number of shares outstanding. The announcement did not specify an amount or expiration date. The Corporation has continued to purchase shares since this announcement and to report purchased volumes in its quarterly earnings releases. In its most recent earnings release dated January 30, 2014, the Corporation stated that first quarter 2014 share purchases are continuing at a pace consistent with fourth quarter 2013 share reduction spending of \$3 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,								
	2013		2012		2011		2010		2009
<i>(millions of dollars, except per share amounts)</i>									
Sales and other operating revenue (1)	420,836		451,509		467,029		370,125		301,500
(1) Sales-based taxes included	30,589		32,409		33,503		28,547		25,936

Net income attributable to ExxonMobil	32,580		44,880		41,060		30,460		19,280
Earnings per common share	7.37		9.70		8.43		6.24		3.99
Earnings per common share - assuming dilution	7.37		9.70		8.42		6.22		3.98
Cash dividends per common share	2.46		2.18		1.85		1.74		1.66
Total assets	346,808		333,795		331,052		302,510		233,323
Long-term debt	6,891		7,928		9,322		12,227		7,129

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 26, 2014, beginning with the section entitled “Report of Independent Registered Public Accounting Firm” and continuing through “Note 19: Income, Sales-Based and Other Taxes”;
•	“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, 2013. 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 (1992)* 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, 2013.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation’s internal control over financial reporting as of December 31, 2013, 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

None.

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 2014 annual meeting of shareholders (the “2014 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 2014 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 2014 Proxy Statement.

Equity Compensation Plan Information						
		(a)			(b)	(c)
					Weighted-Average	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Plan Category		Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights			Exercise Price of Outstanding Options, Warrants and Rights	
		17,358,275	(1)(2)		-	117,260,597 (2)(3)(4)

Equity compensation plans approved by security holders							
Equity compensation plans not approved by security holders		-			-		-
Total	17,358,275				-		117,260,597

(1) *The number of restricted stock units to be settled in shares.*

(2) *Does not include options that ExxonMobil assumed in the 2010 merger with XTO Energy Inc. At year-end 2013, the number of securities to be issued upon exercise of outstanding options under XTO Energy Inc. plans was 1,505,820, and the weighted-average exercise price of such options was \$85.57. No additional awards may be made under those plans.*

(3) *Available shares can be granted in the form of restricted stock, options, or other stock-based awards. Includes 116,619,397 shares available for award under the 2003 Incentive Program and 641,200 shares available for award under the 2004 Non-Employee Director Restricted Stock Plan.*

(4) *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

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 2014 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 2014 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.

FINANCIAL SECTION

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BUSINESS PROFILE

		Earnings After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
Financial		2013	2012	2013	2012	2013	2012	2013	2012
		<i>(millions of dollars)</i>				<i>(percent)</i>		<i>(millions of dollars)</i>	
Upstream									
	United States	4,191	3,925	59,898	57,631	7.0	6.8	9,145	11,080
	Non-U.S.	22,650	25,970	93,071	81,811	24.3	31.7	29,086	25,004
	Total	26,841	29,895	152,969	139,442	17.5	21.4	38,231	36,084
Downstream									
	United States	2,199	3,575	4,757	4,630	46.2	77.2	951	634
	Non-U.S.	1,250	9,615	19,673	19,401	6.4	49.6	1,462	1,628
	Total	3,449	13,190	24,430	24,031	14.1	54.9	2,413	2,262
Chemical									
	United States	2,755	2,220	4,872	4,671	56.5	47.5	963	408
	Non-U.S.	1,073	1,678	15,793	15,477	6.8	10.8	869	1,010
	Total	3,828	3,898	20,665	20,148	18.5	19.3	1,832	1,418
Corporate and financing		(1,538)	(2,103)	(6,489)	(4,527)	-	-	13	35
	Total	32,580	44,880	191,575	179,094	17.2	25.4	42,489	39,799

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

Operating		2013	2012			2013	2012
		<i>(thousands of barrels daily)</i>				<i>(thousands of barrels daily)</i>	
Net liquids production				Refinery throughput			
	United States	431	418		United States	1,819	1,816
	Non-U.S.	1,771	1,767		Non-U.S.	2,766	3,198
	Total	2,202	2,185		Total	4,585	5,014
		<i>(millions of cubic feet daily)</i>				<i>(thousands of barrels daily)</i>	
Natural gas production available for sale				Petroleum product sales			
	United States	3,545	3,822		United States	2,609	2,569

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	Non-U.S.	8,291		8,500		Non-U.S.	3,278		3,605
	Total	11,836		12,322		Total	5,887		6,174
		<i>(thousands of oil-equivalent barrels daily)</i>					<i>(thousands of metric tons)</i>		
Oil-equivalent production (1)		4,175		4,239	Chemical prime product sales (2)				
					United States		9,679		9,381
					Non-U.S.		14,384		14,776
					Total		24,063		24,157

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

(2) Prime product sales include ExxonMobil's share of equity company volumes and finished-product transfers to the Downstream.

FINANCIAL SUMMARY

		2013	2012	2011	2010	2009
		<i>(millions of dollars, except per share amounts)</i>				
Sales and other operating revenue (1)		420,836	451,509	467,029	370,125	301,500
Earnings						
	Upstream	26,841	29,895	34,439	24,097	17,107
	Downstream	3,449	13,190	4,459	3,567	1,781
	Chemical	3,828	3,898	4,383	4,913	2,309
	Corporate and financing	(1,538)	(2,103)	(2,221)	(2,117)	(1,917)
	Net income attributable to ExxonMobil	32,580	44,880	41,060	30,460	19,280
Earnings per common share		7.37	9.70	8.43	6.24	3.99
Earnings per common share – assuming dilution		7.37	9.70	8.42	6.22	3.98
Cash dividends per common share		2.46	2.18	1.85	1.74	1.66
Earnings to average ExxonMobil share of equity (percent)		19.2	28.0	27.3	23.7	17.3
Working capital		(12,416)	321	(4,542)	(3,649)	3,174
Ratio of current assets to current liabilities (times)		0.83	1.01	0.94	0.94	1.06
Additions to property, plant and equipment		37,741	35,179	33,638	74,156	22,491
Property, plant and equipment, less allowances		243,650	226,949	214,664	199,548	139,116
Total assets		346,808	333,795	331,052	302,510	233,323
Exploration expenses, including dry holes		1,976	1,840	2,081	2,144	2,021
Research and development costs		1,044	1,042	1,044	1,012	1,050
Long-term debt		6,891	7,928	9,322	12,227	7,129
Total debt		22,699	11,581	17,033	15,014	9,605
Fixed-charge coverage ratio (times)		55.7	62.4	53.4	42.2	25.8
Debt to capital (percent)		11.2	6.3	9.6	9.0	7.7
Net debt to capital (percent) (2)		9.1	1.2	2.6	4.5	(1.0)
ExxonMobil share of equity at year-end		174,003	165,863	154,396	146,839	110,569
ExxonMobil share of equity per common share		40.14	36.84	32.61	29.48	23.39
Weighted average number of common shares						

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	outstanding (millions)		4,419		4,628		4,870		4,885		4,832
	Number of regular employees at year-end (thousands) (3)		75.0		76.9		82.1		83.6		80.7
	CORS employees not included above (thousands) (4)		9.8		11.1		17.0		20.1		22.0

(1) Sales and other operating revenue includes sales-based taxes of \$30,589 million for 2013, \$32,409 million for 2012, \$33,503 million for 2011, \$28,547 million for 2010 and \$25,936 million for 2009.

(2) Debt net of cash, excluding restricted cash.

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

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

FREQUENTLY USED TERMS

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

Cash Flow From Operations and Asset Sales

Cash flow from operations and asset sales is the sum of the net cash provided by operating activities and proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments 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 proceeds associated with asset sales 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		2013	2012	2011
<i>(millions of dollars)</i>				
Net cash provided by operating activities		44,914	56,170	55,345
Proceeds associated with sales of subsidiaries, property, plant and equipment,				
and sales and returns of investments		2,707	7,655	11,133
Cash flow from operations and asset sales		47,621	63,825	66,478

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		2013	2012	2011
<i>(millions of dollars)</i>				
Business uses: asset and liability perspective				
Total assets		346,808	333,795	331,052
Less liabilities and noncontrolling interests share of assets and liabilities				
		(55,916)	(60,486)	(69,794)

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	Total current liabilities excluding notes and loans payable				
	Total long-term liabilities excluding long-term debt	(87,698)	(90,068)	(83,481)	
	Noncontrolling interests share of assets and liabilities	(8,935)	(6,235)	(7,314)	
	Add ExxonMobil share of debt-financed equity company net assets	6,109	5,775	4,943	
	Total capital employed	200,368	182,781	175,406	
Total corporate sources: debt and equity perspective					
	Notes and loans payable	15,808	3,653	7,711	
	Long-term debt	6,891	7,928	9,322	
	ExxonMobil share of equity	174,003	165,863	154,396	
	Less noncontrolling interests share of total debt	(2,443)	(438)	(966)	
	Add ExxonMobil share of equity company debt	6,109	5,775	4,943	
	Total capital employed	200,368	182,781	175,406	

FREQUENTLY USED TERMS**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				2013	2012	2011
				<i>(millions of dollars)</i>		
Net income attributable to ExxonMobil				32,580	44,880	41,060
Financing costs (after tax)						
Gross third-party debt				(163)	(401)	(153)
ExxonMobil share of equity companies				(239)	(257)	(219)
All other financing costs – net				83	100	116
Total financing costs				(319)	(558)	(256)
Earnings excluding financing costs				32,899	45,438	41,316
Average capital employed				191,575	179,094	170,721
Return on average capital employed – corporate total				17.2%	25.4%	24.2%

QUARTERLY INFORMATION

		2013					2012				
		First	Second	Third	Fourth		First	Second	Third	Fourth	
		Quarter	Quarter	Quarter	Quarter	Year	Quarter	Quarter	Quarter	Quarter	Year
Volumes											
Production of crude oil		<i>(thousands of barrels daily)</i>									
	and natural gas liquids,	2,193	2,182	2,199	2,235	2,202	2,214	2,208	2,116	2,203	2,185
	synthetic oil and bitumen										
	Refinery throughput	4,576	4,466	4,847	4,452	4,585	5,330	4,962	4,929	4,837	5,014
	Petroleum product sales	5,755	5,765	6,031	5,994	5,887	6,316	6,171	6,105	6,108	6,174
Natural gas production		<i>(millions of cubic feet daily)</i>									
	available for sale	13,213	11,354	10,914	11,887	11,836	14,036	11,661	11,061	12,541	12,322
		<i>(thousands of oil-equivalent barrels daily)</i>									
	Oil-equivalent production (1)	4,395	4,074	4,018	4,216	4,175	4,553	4,152	3,960	4,293	4,239
		<i>(thousands of metric tons)</i>									
	Chemical prime product sales	5,910	5,831	6,245	6,077	24,063	6,337	5,972	5,947	5,901	24,157
Summarized financial data											
Sales and other operating		<i>(millions of dollars)</i>									
	revenue (2)(3)	103,378	103,050	108,390	106,018	420,836	118,961	112,398	110,989	109,161	451,509
	Gross profit (4)	30,083	28,689	30,300	29,901	118,973	35,672	32,715	33,209	31,969	133,565
	Net income attributable to										
	ExxonMobil	9,500	6,860	7,870	8,350	32,580	9,450	15,910	9,570	9,950	44,880

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Per share data		<i>(dollars per share)</i>										
Earnings per common share (5)		2.12	1.55	1.79	1.91	7.37		2.00	3.41	2.09	2.20	9.70
Earnings per common share												
- assuming dilution (5)		2.12	1.55	1.79	1.91	7.37		2.00	3.41	2.09	2.20	9.70
Dividends per common share		0.57	0.63	0.63	0.63	2.46		0.47	0.57	0.57	0.57	2.18
Common stock prices												
High		91.93	93.50	95.49	101.74	101.74		87.94	87.67	92.57	93.67	93.67
Low		86.59	85.02	85.61	84.79	84.79		83.19	77.13	82.83	84.70	77.13

- (1) Gas converted to oil-equivalent at 6 million cubic feet = 1 thousand barrels.
- (2) Prior periods' data has been reclassified in certain cases to conform to the 2013 presentation basis.
- (3) Includes amounts for sales-based taxes.
- (4) Gross profit equals sales and other operating revenue less estimated costs associated with products sold.
- (5) 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 450,634 registered shareholders of ExxonMobil common stock at December 31, 2013. At January 31, 2014, the registered shareholders of ExxonMobil common stock numbered 449,312.

On January 29, 2014, the Corporation declared a \$0.63 dividend per common share, payable March 10, 2014.

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

FUNCTIONAL EARNINGS			2013	2012	2011
			<i>(millions of dollars, except per share amounts)</i>		
Earnings (U.S. GAAP)					
Upstream					
	United States		4,191	3,925	5,096
	Non-U.S.		22,650	25,970	29,343
Downstream					
	United States		2,199	3,575	2,268
	Non-U.S.		1,250	9,615	2,191
Chemical					
	United States		2,755	2,220	2,215
	Non-U.S.		1,073	1,678	2,168
Corporate and financing			(1,538)	(2,103)	(2,221)
		Net income attributable to ExxonMobil (U.S. GAAP)	32,580	44,880	41,060
Earnings per common share			7.37	9.70	8.43
Earnings per common share – assuming dilution			7.37	9.70	8.42

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, 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. Risk Factors.

The term "project" as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

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. Price ranges for crude oil, natural gas, refined products, and chemical 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 2040, the world's population is projected to grow to approximately 8.8 billion people, or close to 2 billion more than in 2010. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. As economies and populations grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 35 percent from 2010 to 2040. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organisation for Economic Co-operation and Development).

As expanding prosperity drives global energy demand higher, increasing use of energy-efficient and lower-emission fuels, technologies and practices will continue to help significantly reduce energy consumption and emissions per unit of economic output over time. Substantial efficiency gains are likely in all key aspects of the world's economy through 2040, affecting energy requirements for transportation, power generation, industrial applications, and residential and commercial needs.

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 40 percent from 2010 to 2040. The global growth in transportation demand is likely to account for approximately 70 percent of the growth in liquid fuels demand over this period. Nearly all the world's transportation fleets will continue to run on liquid fuels because they are abundant, widely available, easy to transport, and provide a large quantity of energy in small volumes.

Demand for electricity around the world is likely to increase approximately 90 percent by 2040, led by growth in developing countries. Consistent with this projection, power generation is expected to 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 is likely to grow most significantly and become the leading source of generated electricity by 2040, reflecting the efficiency of gas-fired power plants. Today, coal has the largest fuel share in the power sector, but its share is likely to decline significantly by 2040 as policies are gradually adopted to reduce environmental impacts including those related to local air quality and greenhouse gas emissions. Nuclear power and renewables, led by hydropower and wind, are also expected to grow significantly over the period.

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

Liquid fuels provide the largest share of global energy supplies today due to their broad-based availability, affordability and ease of transportation, distribution and storage to meet consumer needs. By 2040, global demand for liquid fuels is expected to grow to approximately 112 million barrels of oil equivalent per day, an increase of about 25 percent from 2010. This demand will be met by a wide variety of sources. Globally, conventional crude production will likely decline slightly through 2040. However, this decline is expected to be more than offset by rising production from a wide variety of emerging supply sources – including tight oil, deepwater, oil sands, natural gas liquids and biofuels. The world's resource base is sufficient to meet projected demand through 2040 as technology advances continue to expand the availability of economic supply options. However, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel, suitable for a wide variety of applications, and is expected to be the fastest growing major fuel source through 2040. Global demand is expected to rise about 65 percent from 2010 to 2040, with demand likely to increase in all major regions of the world. Helping meet these needs will be significant growth in supplies of unconventional gas – the natural gas found in shale and other rock formations that was once considered uneconomic to produce. About 65 percent of the growth in natural gas supplies is expected to be from unconventional sources, which will account for about one-third of global gas supplies by 2040. Growing natural gas demand will also stimulate significant growth in the worldwide liquefied natural gas (LNG) market, which is expected to reach about 15 percent of global gas demand by 2040.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas by approximately 2025. The share of natural gas is expected to exceed 25 percent by 2040, while the share of coal falls to less than 20 percent. Nuclear power is projected to grow significantly, albeit at a slower pace than otherwise expected in the aftermath of the Fukushima incident in Japan following the earthquake and tsunami in March 2011. Total renewable energy is likely to reach close to 15 percent of total energy by 2040, with biomass, hydro and geothermal contributing a combined share of about 11 percent. Total energy supplied from wind, solar and biofuels is expected to increase close to 450 percent from 2010 to 2040, reaching a combined share of about 4 percent of world energy.

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 2012–2035 will be close to \$19 trillion (measured in 2011 dollars) or close to \$800 billion per year on average.

International accords and underlying regional and national regulations covering greenhouse gas emissions 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 Outlook for Energy, 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 diverse 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 capturing the highest quality opportunities, exercising a disciplined approach to investing and cost management, developing and applying high-impact technologies, maximizing the 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 within 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 2018. Oil equivalent production from North America is expected to increase over the next five years based on current capital activity plans. Currently, this growth area accounts for 32 percent of the Corporation's production. By 2018, it is expected to generate about 35 percent of total volumes. The remainder of the Corporation's production is expected to include contributions from both established operations and new projects around the globe.

In addition to an evolving geographic mix, we expect 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 and oil sands recovery processes, unconventional gas and oil production and

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

LNG is expected to grow from about 45 percent to around 55 percent of the Corporation's output between now and 2018. 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. Risk Factors, 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 2014-2018. 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. Risk Factors. 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.

Downstream

ExxonMobil's Downstream is a large, diversified business with refining, logistics, and marketing complexes around the world. The Corporation has a presence in mature markets in North America and Europe, as well as in 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 31 refineries, located in 17 countries, with distillation capacity of 5.3 million barrels per day and lubricant basestock manufacturing capacity of 126 thousand barrels per day. ExxonMobil's fuels and lubes marketing businesses have significant global reach, with multiple channels to market serving a diverse customer base. Our portfolio of world-renowned brands includes *Exxon*, *Mobil*, *Esso* and *Mobil 1*.

The downstream industry environment remains challenging. Demand weakness and overcapacity in the refining sector will continue to put pressure on margins. In the near term, we see variability in refining margins, with some regions seeing stronger margins as refineries rationalize. In North America, lower raw material and energy cost driven by increasing crude oil and natural gas production has strengthened refining margins in several areas.

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, industry refinery operations, import/export balances, currency fluctuations, seasonal demand, weather and

political climate.

ExxonMobil's long term outlook is that industry refining margins will remain weak as competition 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. Risk Factors, 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.

ExxonMobil's integration across the value chain, from refining to marketing, enhances overall value in both fuels and lubricants businesses.

In the retail fuels marketing business, competition has caused inflation-adjusted margins to decline. In 2013, ExxonMobil completed the previously announced transition of the direct served (i.e., dealer, company-operated) retail network in the U.S. to a more capital-efficient branded distributor model and progressed this same model in portions of Europe. ExxonMobil is increasing investment in its fuels brands and developing multiple programs that will enhance the value of its consumer retail offer. The company's lubricants business continues to grow, leveraging world-class brands and integration with industry-leading basestock refining capability. ExxonMobil remains the market leader in the high value synthetic lubricants sector where competition is increasing.

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 2013, the company completed a hydrotreater project at the Singapore refinery to produce ultra low sulfur diesel, and a cogeneration project at the Augusta, Italy refinery to improve energy efficiency. Additionally, construction of a lower sulfur fuels facility at the joint Saudi Aramco and ExxonMobil SAMREF Refinery in Yanbu, Saudi Arabia is nearly complete. The company is also expanding lubricant basestock manufacturing capacity at refineries in Baytown,

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

Texas and Singapore, and expanding lube oil blending plants in China, Finland, and the U.S. to support future demand growth for finished lubricants in key markets.

Chemical

Worldwide petrochemical demand grew in 2013, led by growing demand from Asia manufacturers and consumers. North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low-cost feedstock and energy savings. Specialty product margins declined reflecting significant new industry capacity following several years of tight supplies.

ExxonMobil sustained its competitive advantage through continued operational excellence, investment and cost discipline, a balanced portfolio of products, integration with refining and upstream operations, all underpinned by proprietary technology.

In 2013 ExxonMobil started up the Singapore Chemical Expansion Project, more than doubling steam cracking capacity at the site and significantly increasing premium and specialty products capacity. Singapore is now ExxonMobil's largest integrated petrochemical complex.

REVIEW OF 2013 AND 2012 RESULTS						
		2013		2012		2011
<i>(millions of dollars)</i>						
Earnings (U.S. GAAP)		32,580		44,880		41,060

2013

Earnings in 2013 of \$32,580 million decreased \$12,300 million from 2012.

2012

Earnings in 2012 of \$44,880 million increased \$3,820 million from 2011.

Upstream						
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			2013		2012		2011
			<i>(millions of dollars)</i>				
Upstream							
	United States		4,191		3,925		5,096
	Non-U.S.		22,650		25,970		29,343
		Total	26,841		29,895		34,439

2013

Upstream earnings were \$26,841 million, down \$3,054 million from 2012. Higher gas realizations, partially offset by lower liquids realizations, increased earnings by \$390 million. Production volume and mix effects decreased earnings by \$910 million. All other items, including lower net gains from asset sales, mainly in Angola, and higher expenses, reduced earnings by \$2.5 billion. On an oil equivalent basis, production was down 1.5 percent compared to 2012. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was essentially flat. Liquids production of 2,202 kbd (thousands of barrels per day) increased 17 kbd compared with 2012. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production was up 1.6 percent, as project ramp up and lower downtime were partially offset by field decline. Natural gas production of 11,836 mcf (millions of cubic feet per day) decreased 486 mcf from 2012. Excluding the impacts of entitlement volumes and divestments, natural gas production was down 1.5 percent, as field decline was partially offset by higher demand, lower downtime, and project ramp up. Earnings from U.S. Upstream operations for 2013 were \$4,191 million, up \$266 million from 2012. Earnings outside the U.S. were \$22,650 million, down \$3,320 million from the prior year.

2012

Upstream earnings were \$29,895 million, down \$4,544 million from 2011. Lower liquids realizations, partly offset by improved natural gas realizations, decreased earnings by about \$100 million. Production volume and mix effects decreased earnings by \$2.3 billion. All other items, including higher operating expenses, unfavorable tax items, lower gains on asset sales, and unfavorable foreign exchange effects, reduced earnings by \$2.1 billion. On an oil equivalent basis, production was down 5.9 percent compared to 2011. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was down 1.7 percent. Liquids production of 2,185 kbd decreased 127 kbd from 2011. Excluding the impacts of entitlement

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

volumes, OPEC quota effects and divestments, liquids production was down 1.6 percent, as field decline was partly offset by project ramp up in West Africa and lower downtime. Natural gas production of 12,322 mcf/d decreased 840 mcf/d from 2011. Excluding the impacts of entitlement volumes and divestments, natural gas production was down 1.9 percent, as field decline was partially offset by higher demand and lower downtime. Earnings from U.S. Upstream operations for 2012 were \$3,925 million, down \$1,171 million from 2011. Earnings outside the U.S. were \$25,970 million, down \$3,373 million.

Upstream additional information								
					2013		2012	2011
					<i>(thousands of barrels daily)</i>			
Volumes Reconciliation (Oil-equivalent production)(1)								
Prior year					4,239		4,506	4,447
	Entitlements - Net Interest				(38)		(129)	(20)
	Entitlements - Price / Spend				(9)		(10)	(104)
	Quotas				3		9	32
	Divestments				(26)		(61)	(43)
	Net growth				6		(76)	194
Current Year					4,175		4,239	4,506

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

Listed below are descriptions of ExxonMobil's entitlement volume effects. These descriptions are provided to facilitate understanding of the terms.

Production Sharing Contract (PSC) Net Interest Reductions are contractual reductions in ExxonMobil's share of production volumes covered by PSCs. These reductions typically occur when cumulative investment returns or production volumes achieve thresholds as specified in the PSCs. Once a net interest reduction has occurred, it typically will not be reversed by subsequent events, such as lower crude oil prices.

Price and Spend Impacts on Volumes are fluctuations in ExxonMobil's share of production volumes caused by changes in oil and gas prices or spending levels from one period to another. For example, at higher prices, fewer barrels are required for ExxonMobil to recover its costs. According to the terms of contractual arrangements or government royalty regimes, price or spending variability can increase or decrease royalty burdens and/or volumes attributable to ExxonMobil. These effects generally vary from period to period with field spending patterns or market prices for

crude oil or natural gas.

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

Downstream							
				2013		2012	2011
				<i>(millions of dollars)</i>			
Downstream							
	United States			2,199		3,575	2,268
	Non-U.S.			1,250		9,615	2,191
		Total		3,449		13,190	4,459

2013

Downstream earnings of \$3,449 million decreased \$9,741 million from 2012 driven by the absence of the \$5.3 billion gain associated with the Japan restructuring. Lower margins, mainly refining, decreased earnings by \$2.9 billion. Volume and mix effects decreased earnings by \$310 million. All other items, including higher operating expenses, unfavorable foreign exchange impacts, and lower divestments, decreased earnings by \$1.2 billion. Petroleum product sales of 5,887 kbd decreased 287 kbd from 2012. U.S. Downstream earnings were \$2,199 million, down \$1,376 million from 2012. Non-U.S. Downstream earnings were \$1,250 million, a decrease of \$8,365 million from the prior year.

2012

Downstream earnings of \$13,190 million increased \$8,731 million from 2011. Stronger refining-driven margins increased earnings by \$2.6 billion, while volume and mix effects increased earnings by about \$200 million. All other items increased earnings by \$5.9 billion due primarily to the \$5.3 billion gain associated with the Japan restructuring and other divestment gains. Petroleum product sales of 6,174 kbd decreased 239 kbd from 2011 due mainly to the Japan restructuring and divestments. U.S. Downstream earnings were \$3,575 million, up \$1,307 million from 2011. Non-U.S. Downstream earnings were \$9,615 million, an increase of \$7,424 million from 2011.

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

Chemical							
				2013		2012	2011
				<i>(millions of dollars)</i>			
Chemical							
	United States			2,755		2,220	2,215
	Non-U.S.			1,073		1,678	2,168
	Total			3,828		3,898	4,383

2013

Chemical earnings of \$3,828 million were \$70 million lower than 2012. The absence of the gain associated with the Japan restructuring decreased earnings by \$630 million. Higher margins increased earnings by \$480 million, while volume and mix effects increased earnings by \$80 million. Prime product sales of 24,063 kt (thousands of metric tons) were down 94 kt from 2012. U.S. Chemical earnings were \$2,755 million, up \$535 million from 2012. Non-U.S. Chemical earnings were \$1,073 million, \$605 million lower than the prior year.

2012

Chemical earnings of \$3,898 million were \$485 million lower than 2011. Margins decreased earnings by \$440 million, while volume effects lowered earnings by \$100 million. All other items increased earnings by \$50 million, as a \$630 million gain associated with the Japan restructuring and favorable tax impacts were mostly offset by unfavorable foreign exchange effects and higher operating expenses. Prime product sales of 24,157 kt were down 849 kt from 2011. U.S. Chemical earnings were \$2,220 million, up \$5 million from 2011. Non-U.S. Chemical earnings were \$1,678 million, \$490 million lower than 2011.

Corporate and Financing							
				2013		2012	2011
				<i>(millions of dollars)</i>			
Corporate and financing				(1,538)		(2,103)	(2,221)

2013

Corporate and financing expenses were \$1,538 million, down \$565 million from 2012, as favorable tax impacts were partially offset by the absence of the Japan restructuring gain.

2012

Corporate and financing expenses were \$2,103 million, down \$118 million from 2011.

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

LIQUIDITY AND CAPITAL RESOURCES						
Sources and Uses of Cash						
			2013		2012	2011
<i>(millions of dollars)</i>						
Net cash provided by/(used in)						
	Operating activities		44,914		56,170	55,345
	Investing activities		(34,201)		(25,601)	(22,165)
	Financing activities		(15,476)		(33,868)	(28,256)
Effect of exchange rate changes			(175)		217	(85)
Increase/(decrease) in cash and cash equivalents			(4,938)		(3,082)	4,839
(December 31)						
Cash and cash equivalents			4,644		9,582	12,664
Cash and cash equivalents - restricted			269		341	404
Total cash and cash equivalents			4,913		9,923	13,068

Total cash and cash equivalents were \$4.9 billion at the end of 2013, \$5.0 billion lower than the prior year. The major sources of funds in 2013 were net income including noncontrolling interests of \$33.4 billion, the adjustment for the noncash provision of \$17.2 billion for depreciation and depletion, and a net debt increase of \$11.6 billion. The major uses of funds included spending for additions to property, plant and equipment of \$33.7 billion, the purchase of shares of ExxonMobil stock of \$16.0 billion, dividends to shareholders of \$10.9 billion and a change in working capital, excluding cash and debt, of \$4.7 billion. Included in total cash and cash equivalents at year-end 2013 was \$0.3 billion of restricted cash.

Total cash and cash equivalents were \$9.9 billion at the end of 2012, \$3.1 billion lower than the prior year. Higher earnings and a higher adjustment for noncash transactions were more than offset by lower proceeds from sales of subsidiaries and property, plant and equipment, a net debt decrease compared to a prior year debt increase, and a higher adjustment for net gains on asset sales. Included in total cash and cash equivalents at year-end 2012 was \$0.3 billion of restricted cash. For additional details, see the Consolidated Statement of Cash Flows.

The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, and may be supplemented by long-term and short-term debt, including a revolving commercial paper program. The Corporation has committed lines of credit of \$6.5 billion which were unused as of December 31, 2013. Cash that may be temporarily available as surplus to the Corporation's immediate needs is carefully managed through counterparty quality and investment guidelines to ensure it is secure and readily available to meet the Corporation's cash requirements and to optimize returns.

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 2013 were \$42.5 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an average investment profile of about \$37 billion per year for the next several years. Actual spending could vary depending on the progress of individual projects and property acquisitions. 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

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

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

2013

Cash provided by operating activities totaled \$44.9 billion in 2013, \$11.3 billion lower than 2012. The major source of funds was net income including noncontrolling interests of \$33.4 billion, a decrease of \$14.2 billion. The noncash provision of \$17.2 billion for depreciation and depletion was higher than 2012. The adjustment for net gains on asset sales was \$1.8 billion compared to an adjustment of \$13.0 billion in 2012. Changes in operational working capital, excluding cash and debt, decreased cash in 2013 by \$4.7 billion.

2012

Cash provided by operating activities totaled \$56.2 billion in 2012, \$0.8 billion higher than 2011. The major source of funds was net income including noncontrolling interests of \$47.7 billion, an increase of \$5.5 billion. The noncash provision of \$15.9 billion for depreciation and depletion was slightly higher than 2011. The adjustments for other noncash transactions and changes in operational working capital, excluding cash and debt, both increased cash in 2012, while the adjustment for net gains on asset sales decreased cash by \$13.0 billion in 2012.

Cash Flow from Investing Activities

2013

Cash used in investment activities netted to \$34.2 billion in 2013, \$8.6 billion higher than 2012. Spending for property, plant and equipment of \$33.7 billion decreased \$0.6 billion from 2012. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of \$2.7 billion compared to \$7.7 billion in 2012. Additional investments and advances were \$3.8 billion higher in 2013.

2012

Cash used in investment activities netted to \$25.6 billion in 2012, \$3.4 billion higher than 2011. Spending for property, plant and equipment of \$34.3 billion increased \$3.3 billion from 2011. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of \$7.7 billion compared to \$11.1 billion in 2011. The decrease reflects that a \$3.6 billion deposit was received in 2011 for a sale that closed in 2012. Additional investments and advances were \$3.0 billion lower in 2012.

Cash Flow from Financing Activities

2013

Cash used in financing activities was \$15.5 billion in 2013, \$18.4 billion lower than 2012. Dividend payments on common shares increased to \$2.46 per share from \$2.18 per share and totaled \$10.9 billion, a pay-out of 33 percent of net income. Total debt increased \$11.1 billion to \$22.7 billion at year-end.

ExxonMobil share of equity increased \$8.1 billion to \$174.0 billion. The addition to equity for earnings of \$32.6 billion was partially offset by reductions for distributions to ExxonMobil shareholders of \$10.9 billion of dividends and \$15.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding.

During 2013, Exxon Mobil Corporation purchased 177 million shares of its common stock for the treasury at a gross cost of \$16.0 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 3.7 percent from 4,502 million to 4,335 million at the end of 2013. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2012

Cash used in financing activities was \$33.9 billion in 2012, \$5.6 billion higher than 2011. Dividend payments on common shares increased to \$2.18 per share from \$1.85 per share and totaled \$10.1 billion, a pay-out of 22 percent of net income. Total debt decreased \$5.5 billion to \$11.6 billion at year-end.

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

ExxonMobil share of equity increased \$11.5 billion to \$165.9 billion. The addition to equity for earnings of \$44.9 billion was partially offset by reductions for distributions to ExxonMobil shareholders of \$10.1 billion of dividends and \$20.0 billion of purchases of shares of ExxonMobil stock to reduce shares outstanding.

During 2012, Exxon Mobil Corporation purchased 244 million shares of its common stock for the treasury at a gross cost of \$21.1 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 were reduced by 4.9 percent from 4,734 million to 4,502 million at the end of 2012. Purchases were made in both the open market and through negotiated transactions.

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

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2013. It combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

	Note Reference Number	Payments Due by Period					2019 and Beyond	Total
		2014	2015-2018					
<i>(millions of dollars)</i>								
Long-term debt (1)	14	-	3,052			3,839	6,891	
– Due in one year (2)	6	1,034	-			-	1,034	
Asset retirement obligations (3)	9	799	3,026			9,163	12,988	
Pension and other postretirement obligations (4)	17	2,983	4,379			14,074	21,436	
Operating leases (5)	11	2,391	3,530			1,517	7,438	
Unconditional purchase obligations (6)	16	144	629			463	1,236	
Take-or-pay obligations (7)		3,060	10,893			15,657	29,610	
Firm capital commitments (8)		19,258	9,616			885	29,759	

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 \$7.8 billion as of December 31, 2013, 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 19, Income, Sales-Based and Other Taxes.

Notes:

(1) Includes capitalized lease obligations of \$375 million.

(2) The amount due in one year is included in notes and loans payable of \$15,808 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 2014 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 \$1,236 million mainly pertain to pipeline throughput agreements and include \$457 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 \$29,610 million mainly pertain to pipeline, manufacturing supply and terminaling agreements.*
- (8) *Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately \$29.8 billion. These commitments were primarily associated with Upstream projects outside the U.S., of which \$16.3 billion was associated with projects in Canada, Australia, Africa, United Arab Emirates and Malaysia. The Corporation expects to fund the majority of these projects with internally generated funds that may be supplemented by long-term and short-term debt, including a revolving commercial paper program.*

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

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2013, for guarantees relating to notes, loans and performance under contracts (Note 16). Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure. These 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.

Financial Strength

On December 31, 2013, the Corporation's unused short-term committed lines of credit totaled approximately \$5.9 billion (Note 6) and unused long-term committed lines of credit totaled approximately \$0.6 billion (Note 14).

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

	2013	2012	2011
Fixed-charge coverage ratio (times)	55.7	62.4	53.4
Debt to capital (percent)	11.2	6.3	9.6
Net debt to capital (percent)	9.1	1.2	2.6

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

As discussed in Note 16, 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 material 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. Refer to Note 16 for additional information on legal proceedings and other contingencies.

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

CAPITAL AND EXPLORATION EXPENDITURES										
		2013					2012			
		U.S.	Non-U.S.	Total		U.S.	Non-U.S.	Total		
<i>(millions of dollars)</i>										
Upstream (1)		9,145	29,086	38,231		11,080	25,004	36,084		
Downstream		951	1,462	2,413		634	1,628	2,262		
Chemical		963	869	1,832		408	1,010	1,418		
Other		13	-	13		35	-	35		
	Total	11,072	31,417	42,489		12,157	27,642	39,799		
<i>(1) Exploration expenses included.</i>										

Capital and exploration expenditures in 2013 were \$42.5 billion, including \$4.3 billion for acquisitions, as the Corporation continued to pursue opportunities to find and produce new supplies of oil and natural gas to meet global demand for energy. The Corporation anticipates an average investment profile of about \$37 billion per year for the next several years. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of \$38.2 billion in 2013 was up 6 percent from 2012. Property acquisition costs in the Upstream in 2013 of \$4.2 billion were \$1.2 billion higher than in 2012. Investments in 2013 included projects in the U.S. Gulf of Mexico and Alaska, exploration in Russia 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 66 percent of total proved reserves at year-end 2013, and has been over 60 percent for the last ten years, indicating that proved reserves are consistently moved from undeveloped to developed status.

Capital investments in the Downstream totaled \$2.4 billion in 2013, an increase of \$0.2 billion from 2012, mainly reflecting higher refining margin improvement project spending. The Chemical capital expenditures of \$1.8 billion increased \$0.4 billion from 2012 with higher investments in the U.S., Saudi Arabia and China more than offsetting reduced spending on the completed Singapore Chemical Plant expansion.

TAXES										
		2013			2012			2011		
<i>(millions of dollars)</i>										

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Income taxes		24,263		31,045		31,051
	<i>Effective income tax rate</i>	<i>48%</i>		<i>44%</i>		<i>46%</i>
Sales-based taxes		30,589		32,409		33,503
All other taxes and duties		36,396		38,857		43,544
	Total	91,248		102,311		108,098

2013

Income, sales-based and all other taxes and duties totaled \$91.2 billion in 2013, a decrease of \$11.1 billion or 11 percent from 2012. Income tax expense, both current and deferred, was \$24.3 billion, \$6.8 billion lower than 2012, with the impact of lower earnings partially offset by the higher effective tax rate. The effective tax rate was 48 percent compared to 44 percent in the prior year due to the absence of favorable tax impacts on divestments. Sales-based and all other taxes and duties of \$67.0 billion in 2013 decreased \$4.3 billion reflecting the 2012 Japan restructuring.

2012

Income, sales-based and all other taxes and duties totaled \$102.3 billion in 2012, a decrease of \$5.8 billion or 5 percent from 2011. Income tax expense, both current and deferred, was \$31.0 billion, flat with 2011, with the impact of higher earnings offset by the lower effective tax rate. The effective tax rate was 44 percent compared to 46 percent in the prior year due to a lower effective tax rate on divestments. Sales-based and all other taxes and duties of \$71.3 billion in 2012 decreased \$5.8 billion reflecting the Japan restructuring.

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

ENVIRONMENTAL MATTERS

Environmental Expenditures				
			2013	2012
			<i>(millions of dollars)</i>	
Capital expenditures			2,474	1,989
Other expenditures			3,538	3,523
	Total		6,012	5,512

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. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2013 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about \$6.0 billion. The total cost for such activities is expected to remain in this range in 2014 and 2015 (with capital expenditures approximately 45 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 2013 for environmental liabilities were \$321 million (\$391 million in 2012) and the balance sheet reflects accumulated liabilities of \$773 million as of December 31, 2013, and \$841 million as of December 31, 2012.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations (1)	2013	2012	2011
Crude oil and NGL (\$/barrel)	97.48	100.29	100.79
Natural gas (\$/kcf)	4.60	3.90	4.65
<i>(1) Consolidated subsidiaries.</i>			

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 \$350 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 \$175 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.

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

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 35 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.

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 13. 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 use of derivative clearing exchanges and 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.

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. The Corporation has access to significant

capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, and may be supplemented by long-term and short-term debt, including a revolving commercial paper program. 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.

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.

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

CRITICAL ACCOUNTING ESTIMATES

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 Corporation's accounting policies are summarized in Note 1.

Oil and Gas Reserves

Evaluations of oil and gas reserves are important to the effective management of upstream assets. They are an integral part of investment decisions about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the basis to calculate unit-of-production depreciation rates and to evaluate impairment.

Oil and gas reserves include both proved and unproved reserves. 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. 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 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 reserve estimation process are covered in Disclosure of Reserves in Item 2.

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 66 percent of total proved reserves at year-end 2013 (including both consolidated and equity company reserves), and has been over 60 percent for the last ten years, indicating that proved reserves are consistently moved from undeveloped to developed status.

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 year-end costs that are used in the estimation of reserves. Revisions can also result from significant changes in development strategy or production equipment/facility capacity.

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. 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. An asset group would be impaired if its undiscounted cash flows were less than the asset's carrying value. Impairments are measured by the amount by which the carrying value exceeds 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.

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

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses 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. Potential 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 current period operating losses combined with a history and forecast of operating or cash flow losses.

In general, the Corporation does not view temporarily low prices or margins 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 for capital investment decisions. Volumes are based on 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 ones used in the supplemental oil and gas disclosure and could be lower or higher for any given year.

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain 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. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations are disclosed in Note 9 to the financial statements.

Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and 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. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in Note 10 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, liabilities, revenues and expenses. Amounts representing the Corporation's interest in the underlying net assets of other significant entities that it does not control, but over which it exercises significant influence, are accounted for using the equity method of accounting.

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 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 share of all assets and liabilities in these partially owned companies rather than only its interest in net equity. This method of accounting for investments in partially-owned companies is not permitted by U.S. 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 U.S. GAAP standards, the Corporation includes its share of debt of these partially-owned companies in the determination of average capital employed.

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

Pension Benefits

The Corporation and its affiliates sponsor over 100 defined benefit (pension) plans in about 50 countries. Pension and Other Postretirement Benefits (Note 17) 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 U.S., pension obligations are financed in advance through segregated assets or insurance arrangements. These plans are managed in compliance with the requirements of governmental authorities and meet or exceed required funding levels as measured by relevant actuarial and government standards at the mandated measurement dates. In determining liabilities and required contributions, these standards often require approaches and assumptions that differ from those used for accounting purposes.

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

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations and the long-term rate for future salary increases. 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 2013 was 7.25 percent. The 10 year and 20 year actual returns on U.S. pension plan assets were 7 percent and 9 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 percentages 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 \$150 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 16.

The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable, and 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. For purposes of our litigation contingency disclosures, "significant" includes material matters as well as other items which management believes should be disclosed.

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 material 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.

The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained

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

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 or expected to be 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 19.

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.

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.

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 (1992)* 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, 2013.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2013, as stated in their report included in the Financial Section of this report.

Rex W. Tillerson

Chief Executive Officer

Andrew P. Swiger

Senior Vice President

(Principal Financial Officer)

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Patrick T. Mulva

Vice President and Controller

(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2013, and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on criteria established in *Internal Control – Integrated Framework (1992)* 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 26, 2014

CONSOLIDATED STATEMENT OF INCOME

		Note				
		Reference				
		Number	2013	2012	2011	
<i>(millions of dollars)</i>						
Revenues and other income						
	Sales and other operating revenue <i>(1)</i>		420,836	451,509	467,029	
	Income from equity affiliates	7	13,927	15,010	15,289	
	Other income		3,492	14,162	4,111	
	Total revenues and other income		438,255	480,681	486,429	
Costs and other deductions						
	Crude oil and product purchases		244,156	263,535	266,534	
	Production and manufacturing expenses		40,525	38,521	40,268	
	Selling, general and administrative expenses		12,877	13,877	14,983	
	Depreciation and depletion		17,182	15,888	15,583	
	Exploration expenses, including dry holes		1,976	1,840	2,081	
	Interest expense		9	327	247	
	Sales-based taxes <i>(1)</i>	19	30,589	32,409	33,503	
	Other taxes and duties	19	33,230	35,558	39,973	
	Total costs and other deductions		380,544	401,955	413,172	
Income before income taxes						
	Income taxes	19	24,263	31,045	31,051	
Net income including noncontrolling interests						
	Net income attributable to noncontrolling interests		868	2,801	1,146	
Net income attributable to ExxonMobil						
			32,580	44,880	41,060	
Earnings per common share <i>(dollars)</i>						
		12	7.37	9.70	8.43	
Earnings per common share - assuming dilution <i>(dollars)</i>						
		12	7.37	9.70	8.42	

(1) Sales and other operating revenue includes sales-based taxes of \$30,589 million for 2013, \$32,409 million for 2012 and \$33,503 million for 2011.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

					2013		2012		2011
<i>(millions of dollars)</i>									
Net income including noncontrolling interests					33,448		47,681		42,206
Other comprehensive income (net of income taxes)									
	Foreign exchange translation adjustment				(3,620)		920		(867)
	Adjustment for foreign exchange translation (gain)/loss								
	included in net income				(23)		(4,352)		-
	Postretirement benefits reserves adjustment (excluding amortization)				3,174		(3,574)		(4,907)
	Amortization and settlement of postretirement benefits reserves								
	adjustment included in net periodic benefit costs				1,820		2,395		1,217
	Change in fair value of cash flow hedges				-		-		28
	Realized (gain)/loss from settled cash flow hedges included in net income				-		-		(83)
	Total other comprehensive income				1,351		(4,611)		(4,612)
Comprehensive income including noncontrolling interests					34,799		43,070		37,594
	Comprehensive income attributable to noncontrolling interests				760		1,251		834
Comprehensive income attributable to ExxonMobil					34,039		41,819		36,760

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

CONSOLIDATED BALANCE SHEET

			Note			
			Reference		Dec. 31	Dec. 31
			Number		2013	2012
<i>(millions of dollars)</i>						
Assets						
Current assets						
		Cash and cash equivalents			4,644	9,582
		Cash and cash equivalents - restricted			269	341
		Notes and accounts receivable, less estimated doubtful amounts	6		33,152	34,987
		Inventories				
		Crude oil, products and merchandise	3		12,117	10,836
		Materials and supplies			4,018	3,706
		Other current assets			5,108	5,008
		Total current assets			59,308	64,460
		Investments, advances and long-term receivables	8		36,328	34,718
		Property, plant and equipment, at cost, less accumulated depreciation				
		and depletion	9		243,650	226,949
		Other assets, including intangibles, net			7,522	7,668
		Total assets			346,808	333,795
Liabilities						
Current liabilities						
		Notes and loans payable	6		15,808	3,653
		Accounts payable and accrued liabilities	6		48,085	50,728
		Income taxes payable			7,831	9,758
		Total current liabilities			71,724	64,139
		Long-term debt	14		6,891	7,928
		Postretirement benefits reserves	17		20,646	25,267
		Deferred income tax liabilities	19		40,530	37,570
		Long-term obligations to equity companies			4,742	3,555
		Other long-term obligations			21,780	23,676
		Total liabilities			166,313	162,135
Commitments and contingencies			16			
Equity						
		Common stock without par value				
		(9,000 million shares authorized, 8,019 million shares issued)			10,077	9,653

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	Earnings reinvested			387,432		365,727
	Accumulated other comprehensive income			(10,725)		(12,184)
	Common stock held in treasury					
	(3,684 million shares in 2013 and 3,517 million shares in 2012)			(212,781)		(197,333)
	ExxonMobil share of equity			174,003		165,863
	Noncontrolling interests			6,492		5,797
	Total equity			180,495		171,660
	Total liabilities and equity			346,808		333,795

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

CONSOLIDATED STATEMENT OF CASH FLOWS

				Note					
				Reference					
				Number	2013	2012	2011		
<i>(millions of dollars)</i>									
Cash flows from operating activities									
	Net income including noncontrolling interests				33,448	47,681	42,206		
	Adjustments for noncash transactions								
		Depreciation and depletion			17,182	15,888	15,583		
		Deferred income tax charges/(credits)			754	3,142	142		
		Postretirement benefits expense							
			in excess of/(less than) net payments		2,291	(315)	544		
		Other long-term obligation provisions							
			in excess of/(less than) payments		(2,566)	1,643	(151)		
	Dividends received greater than/(less than) equity in current								
		earnings of equity companies			3	(1,157)	(273)		
	Changes in operational working capital, excluding cash and debt								
		Reduction/(increase)		- Notes and accounts receivable	(305)	(1,082)	(7,906)		
				- Inventories	(1,812)	(1,873)	(2,208)		
				- Other current assets	(105)	(42)	222		
		Increase/(reduction)		- Accounts and other payables	(2,498)	3,624	8,880		
	Net (gain) on asset sales			5	(1,828)	(13,018)	(2,842)		
	All other items - net				350	1,679	1,148		
		Net cash provided by operating activities			44,914	56,170	55,345		
Cash flows from investing activities									
	Additions to property, plant and equipment				(33,669)	(34,271)	(30,975)		
	Proceeds associated with sales of subsidiaries, property, plant								
		and equipment, and sales and returns of investments		5	2,707	7,655	11,133		
	Decrease/(increase) in restricted cash and cash equivalents				72	63	224		
	Additional investments and advances				(4,435)	(598)	(3,586)		
	Collection of advances				1,124	1,550	1,119		
	Additions to marketable securities				-	-	(1,754)		
	Sales of marketable securities				-	-	1,674		
		Net cash used in investing activities			(34,201)	(25,601)	(22,165)		

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Cash flows from financing activities						
	Additions to long-term debt			345	995	702
	Reductions in long-term debt			(13)	(147)	(266)
	Additions to short-term debt			16	958	1,063
	Reductions in short-term debt			(756)	(4,488)	(1,103)
	Additions/(reductions) in debt with three months or less maturity			12,012	(226)	1,561
	Cash dividends to ExxonMobil shareholders			(10,875)	(10,092)	(9,020)
	Cash dividends to noncontrolling interests			(304)	(327)	(306)
	Changes in noncontrolling interests			(1)	204	(16)
	Tax benefits related to stock-based awards			48	130	260
	Common stock acquired			(15,998)	(21,068)	(22,055)
	Common stock sold			50	193	924
	Net cash used in financing activities			(15,476)	(33,868)	(28,256)
	Effects of exchange rate changes on cash			(175)	217	(85)
	Increase/(decrease) in cash and cash equivalents			(4,938)	(3,082)	4,839
	Cash and cash equivalents at beginning of year			9,582	12,664	7,825
	Cash and cash equivalents at end of year			4,644	9,582	12,664

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

ExxonMobil Share of Equity									
				Accumulated		Common			
				Other		Stock		ExxonMobil	
		Earnings		Comprehensive		Held in		Share of	
		Reinvested		Income		Treasury		controlling	
		Stock		Equity		Equity		Interests	
								Total	
								Equity	
<i>(millions of dollars)</i>									
Balance as of December 31, 2010		9,371	298,899	(4,823)	(156,608)	146,839	5,840	152,679	
Amortization of stock-based awards		742	-	-	-	742	-	742	
Tax benefits related to stock-based awards		202	-	-	-	202	-	202	
Other		(803)	-	-	-	(803)	(5)	(808)	
Net income for the year		-	41,060	-	-	41,060	1,146	42,206	
Dividends - common shares		-	(9,020)	-	-	(9,020)	(306)	(9,326)	
Other comprehensive income		-	-	(4,300)	-	(4,300)	(312)	(4,612)	
Acquisitions, at cost		-	-	-	(22,055)	(22,055)	(15)	(22,070)	
Dispositions		-	-	-	1,731	1,731	-	1,731	
Balance as of December 31, 2011		9,512	330,939	(9,123)	(176,932)	154,396	6,348	160,744	
Amortization of stock-based awards		806	-	-	-	806	-	806	
Tax benefits related to stock-based awards		178	-	-	-	178	-	178	
Other		(843)	-	-	-	(843)	(1,441)	(2,284)	
Net income for the year		-	44,880	-	-	44,880	2,801	47,681	
Dividends - common shares		-	(10,092)	-	-	(10,092)	(327)	(10,419)	
Other comprehensive income		-	-	(3,061)	-	(3,061)	(1,550)	(4,611)	
Acquisitions, at cost		-	-	-	(21,068)	(21,068)	(34)	(21,102)	

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Dispositions	-	-	-	667	667	-	667
Balance as of December 31, 2012	9,653	365,727	(12,184)	(197,333)	165,863	5,797	171,660
Amortization of stock-based awards	761	-	-	-	761	-	761
Tax benefits related to stock-based awards	162	-	-	-	162	-	162
Other	(499)	-	-	-	(499)	240	(259)
Net income for the year	-	32,580	-	-	32,580	868	33,448
Dividends - common shares	-	(10,875)	-	-	(10,875)	(304)	(11,179)
Other comprehensive income	-	-	1,459	-	1,459	(108)	1,351
Acquisitions, at cost	-	-	-	(15,998)	(15,998)	(1)	(15,999)
Dispositions	-	-	-	550	550	-	550
Balance as of December 31, 2013	10,077	387,432	(10,725)	(212,781)	174,003	6,492	180,495

		Issued	Held in Treasury	Outstanding
Common Stock Share Activity				
		<i>(millions of shares)</i>		
Balance as of December 31, 2010		8,019	(3,040)	4,979
Acquisitions		-	(278)	(278)
Dispositions		-	33	33
Balance as of December 31, 2011		8,019	(3,285)	4,734
Acquisitions		-	(244)	(244)
Dispositions		-	12	12
Balance as of December 31, 2012		8,019	(3,517)	4,502
Acquisitions		-	(177)	(177)
Dispositions		-	10	10
Balance as of December 31, 2013		8,019	(3,684)	4,335

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 2013 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation. The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses.

Amounts representing the Corporation's interest in entities that it does not control, but over which it 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."

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

The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in Accumulated Other Comprehensive Income.

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. 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).

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.

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

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 and 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves.

Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using unit-of-production rates 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 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 and are expensed as incurred. 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.

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, refining and chemical margins and foreign currency exchange rates. Annual volumes are based on 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. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds 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 valuation allowances are reviewed at least annually.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any 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.

Asset Retirement Obligations and Environmental Liabilities. The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. The costs associated with these liabilities are capitalized as part of the related assets and depreciated. 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 price of the stock at the date of grant and is recognized in income over the requisite service period. See Note 15, Incentive Program, for further details.

2. Accounting Changes

The Corporation did not adopt authoritative guidance in 2013 that had a material impact on the Corporation's financial statements.

3. Miscellaneous Financial Information

Research and development expenses totaled \$1,044 million in 2013, \$1,042 million in 2012 and \$1,044 million in 2011.

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Net income included before-tax aggregate foreign exchange transaction gains of \$155 million and \$159 million, and losses of \$184 million in 2013, 2012 and 2011, respectively.

In 2013, 2012 and 2011, net income included gains of \$282 million, \$328 million and \$292 million, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by \$21.2 billion and \$21.3 billion at December 31, 2013, and 2012, respectively.

Crude oil, products and merchandise as of year-end 2013 and 2012 consist of the following:

			2013		2012
			<i>(billions of dollars)</i>		
Petroleum products			3.9		3.6
Crude oil			4.7		4.0
Chemical products			2.9		2.9
Gas/other			0.6		0.3
	Total		12.1		10.8

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. Other Comprehensive Income Information

		Cumulative		Post-		Unrealized			
		Foreign		retirement		Change in			
		Exchange		Benefits		Fair Value			
ExxonMobil Share of Accumulated Other		Translation		Reserves		on Cash			
Comprehensive Income		Adjustment		Adjustment		Flow Hedges		Total	
<i>(millions of dollars)</i>									
Balance as of December 31, 2010		5,011		(9,889)		55		(4,823)	
Current period change excluding amounts reclassified									
from accumulated other comprehensive income		(843)		(4,557)		28		(5,372)	
Amounts reclassified from accumulated other comprehensive income		-		1,155		(83)		1,072	
Total change in accumulated other comprehensive income		(843)		(3,402)		(55)		(4,300)	
Balance as of December 31, 2011		4,168		(13,291)		-		(9,123)	
Balance as of December 31, 2011		4,168		(13,291)		-		(9,123)	
Current period change excluding amounts reclassified									
from accumulated other comprehensive income		842		(3,402)		-		(2,560)	
Amounts reclassified from accumulated other comprehensive income		(2,600)		2,099		-		(501)	
Total change in accumulated other comprehensive income		(1,758)		(1,303)		-		(3,061)	
Balance as of December 31, 2012		2,410		(14,594)		-		(12,184)	
Balance as of December 31, 2012		2,410		(14,594)		-		(12,184)	
Current period change excluding amounts reclassified									
from accumulated other comprehensive income		(3,233)		2,963		-		(270)	
Amounts reclassified from accumulated other comprehensive income		(23)		1,752		-		1,729	
Total change in accumulated other comprehensive income		(3,256)		4,715		-		1,459	
Balance as of December 31, 2013		(846)		(9,879)		-		(10,725)	

Amounts Reclassified Out of Accumulated Other					
Comprehensive Income - Before-tax Income/(Expense)		2013		2012	2011
		<i>(millions of dollars)</i>			
Foreign exchange translation gain/(loss) included in net income					
	(Statement of Income line: Other income)	23		4,352	-
Amortization and settlement of postretirement benefits reserves					
	adjustment included in net periodic benefit costs (1)	(2,616)		(3,621)	(1,761)
Realized gain from settled cash flow hedges included in net income					
	(Statement of Income line: Sales and other operating revenue)	-		-	133

(1) These accumulated other comprehensive income components are included in the computation of net periodic pension cost. (See Note 17 – Pension and Other Postretirement Benefits for additional details.)

Income Tax (Expense)/Credit For					
Components of Other Comprehensive Income		2013		2012	2011
		<i>(millions of dollars)</i>			
Foreign exchange translation adjustment		218		(236)	89
Postretirement benefits reserves adjustment					
	Postretirement benefits reserves adjustment (excluding amortization)	(1,540)		1,619	2,039
Amortization and settlement of postretirement benefits reserves					
	adjustment included in net periodic benefit costs	(796)		(1,226)	(544)
Unrealized change in fair value on cash flow hedges					
	Change in fair value of cash flow hedges	-		-	(16)
	Settled cash flow hedges included in net income	-		-	50
Total		(2,118)		157	1,618

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**5. Cash Flow Information**

The Consolidated Statement of Cash Flows provides information about changes in cash and cash equivalents. Highly liquid investments with maturities of three months or less when acquired are classified as cash equivalents.

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 a partial interest in Iraq, the sale of Downstream affiliates in the Caribbean and the sale of service stations in 2013; the Japan restructuring, the sale of an Upstream property in Angola, exchanges of Upstream properties, the sale of U.S. service stations, and the sale of the Downstream affiliates in Malaysia and Switzerland in 2012; and from the sale of some Upstream Canadian, U.K. and other producing properties and assets, and the sale of U.S. service stations in 2011. These gains are reported in “Other income” on the Consolidated Statement of Income.

In 2012, the Corporation’s interest in a cost company was redeemed. As part of the redemption, a variable note due in 2035 issued by Mobil Services (Bahamas) Ltd. was assigned to a consolidated ExxonMobil affiliate. This note is no longer classified as third party long-term debt. This assignment did not result in a “Reduction in long-term debt” on the Statement of Cash Flows.

In 2012, ExxonMobil completed asset exchanges, primarily noncash transactions, of approximately \$1 billion. This amount is not included in the “Sales of subsidiaries, investments, and property, plant and equipment” or the “Additions to property, plant and equipment” lines on the Statement of Cash Flows.

In 2011, included in “Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments” is a \$3.6 billion deposit for an asset that was sold in 2012.

	2013	2012	2011
	<i>(millions of dollars)</i>		
Cash payments for interest	426	555	557
Cash payments for income taxes	25,066	24,349	27,254

6. Additional Working Capital Information

	Dec. 31 2013	Dec. 31 2012
	<i>(millions of dollars)</i>	
Notes and accounts receivable		
Trade, less reserves of \$112 million and \$109 million	25,993	28,373
Other, less reserves of \$28 million and \$36 million	7,159	6,614
Total	33,152	34,987

Notes and loans payable						
	Bank loans			722		663
	Commercial paper			14,051		1,963
	Long-term debt due within one year			1,034		1,025
	Other			1		2
		Total		15,808		3,653
Accounts payable and accrued liabilities						
	Trade payables			30,920		33,789
	Payables to equity companies			6,587		6,114
	Accrued taxes other than income taxes			3,883		4,130
	Other			6,695		6,695
		Total		48,085		50,728

The Corporation has short-term committed lines of credit of \$5.9 billion which were unused as of December 31, 2013. The majority of these lines are available for general corporate purposes, however \$0.5 billion has been designated as specifically supporting commercial paper programs. The weighted-average interest rate on short-term borrowings outstanding was 0.4 percent and 1.7 percent at December 31, 2013, and 2012, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**7. Equity Company Information**

The summarized financial information below includes amounts related to certain less-than-majority-owned companies and majority-owned subsidiaries where minority shareholders possess the right to participate in significant management decisions (see Note 1). These companies are primarily engaged in oil and gas exploration and production, natural gas marketing and refining operations in North America; natural gas exploration, production and distribution, and downstream operations in Europe; and research, exploration, production, liquefied natural gas (LNG) operations, refining operations, petrochemical manufacturing, fuel sales and power generation in Asia. Also included are several refining, petrochemical manufacturing and marketing ventures.

The Corporation's ownership in these ventures is in the form of shares in corporate joint ventures as well as interests in partnerships. Differences between the company's carrying value of an equity investment and its underlying equity in the net assets of the affiliate are assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the factors giving rise to the difference. The amortization of this difference, as appropriate, is included in "income from equity affiliates."

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 13 percent, 16 percent and 19 percent in the years 2013, 2012 and 2011, respectively.

In 2013, the Corporation and Rosneft established various entities to conduct exploration and research activities. Periods of disproportionate funding will result in the Corporation recognizing, during the early phases of the projects, an investment that is larger than its equity share of these entities. These joint ventures are considered Variable Interest Entities (VIEs). However, since the Corporation is not the primary beneficiary of these entities the joint ventures are reported as equity companies. The Corporation's maximum exposure to loss from these joint ventures is limited to its investment of \$0.1 billion and firm commitments of \$1.1 billion at December 31, 2013.

		2013			2012			2011		
Equity Company		ExxonMobil			ExxonMobil			ExxonMobil		
Financial Summary		Total	Share		Total	Share		Total	Share	
<i>(millions of dollars)</i>										
Total revenues		236,161	68,084		224,953	67,572		204,635	65,147	
Income before income taxes		69,454	19,999		69,411	20,882		68,908	20,892	
Income taxes		21,618	6,069		20,703	5,868		19,812	5,603	
	Income from equity affiliates	47,836	13,930		48,708	15,014		49,096	15,289	
Current assets		62,398	19,545		59,612	18,483		52,879	17,317	
Long-term assets		116,450	35,695		111,131	33,798		96,908	30,833	
	Total assets	178,848	55,240		170,743	52,281		149,787	48,150	
Current liabilities		54,550	15,243		49,698	14,265		41,016	12,454	

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Long-term liabilities		68,857		20,873		68,855		19,715		62,472		18,728
Net assets		55,441		19,124		52,190		18,301		46,299		16,968

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A list of significant equity companies as of December 31, 2013, together with the Corporation's percentage ownership interest, is detailed below:

		Percentage Ownership Interest		
	Upstream			
	Aera Energy LLC	48		
	BEB Erdgas und Erdoel GmbH & Co. KG	50		
	Cameroon Oil Transportation Company S.A.	41		
	Castle Peak Power Company Limited	60		
	Cross Timbers Energy, LLC	50		
	Golden Pass LNG Terminal LLC	18		
	Karmorneftegaz Holding SARL	33		
	LLC Arctic Research and Design Center For Continental Shelf Development	33		
	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.	71		
	Trizneft Pilot SARL	49		
	Tuapsemorneftegaz Holding SARL	33		
	Downstream			
	Chalmette Refining, LLC	50		
	Fujian Refining & Petrochemical Co. Ltd.	25		
	Saudi Aramco Mobil Refinery Company Ltd.	50		
	TonenGeneral Sekiyu K.K.	22		
	Chemical			
	Al-Jubail Petrochemical Company	50		
	Infineum Holdings B.V.	50		
	Infineum USA L.P.	50		
	Saudi Yanbu Petrochemical Co.	50		

8. Investments, Advances and Long-Term Receivables

			Dec. 31, 2013		Dec. 31, 2012
			<i>(millions of dollars)</i>		
Companies carried at equity in underlying assets					
	Investments		19,619		18,530
	Advances		10,476		9,959
		Total equity company investments and advances	30,095		28,489
Companies carried at cost or less and stock investments carried at fair value					
			115		437
Long-term receivables and miscellaneous investments at cost or less, net of reserves					
		of \$2,938 million and \$2,499 million	6,118		5,792
		Total	36,328		34,718

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

9. Property, Plant and Equipment and Asset Retirement Obligations

		December 31, 2013		December 31, 2012	
Property, Plant and Equipment		Cost	Net	Cost	Net
<i>(millions of dollars)</i>					
Upstream		336,359	197,554	313,181	181,795
Downstream		54,456	23,219	53,737	23,053
Chemical		29,487	13,965	29,437	14,085
Other		14,215	8,912	12,959	8,016
	Total	434,517	243,650	409,314	226,949

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 \$190,867 million at the end of 2013 and \$182,365 million at the end of 2012. Interest capitalized in 2013, 2012 and 2011 was \$309 million, \$506 million and \$593 million, respectively.

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain 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. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations 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:

			2013		2012
			<i>(millions of dollars)</i>		
Beginning balance			11,973		10,578
	Accretion expense and other provisions		785		709
	Reduction due to property sales		(97)		(176)
	Payments made		(664)		(816)
	Liabilities incurred		603		163
	Foreign currency translation		(344)		290
	Revisions		732		1,225
Ending balance			12,988		11,973

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**10. Accounting for Suspended Exploratory Well Costs**

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. The term “project” as used in this report can refer to a variety of different activities and does not necessarily have the same meaning as in any government payment transparency reports.

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:

			2013		2012		2011	
			<i>(millions of dollars)</i>					
Balance beginning at January 1			2,679		2,881		2,893	
Additions pending the determination of proved reserves			293		868		310	
Charged to expense			(52)		(95)		(213)	
Reclassifications to wells, facilities and equipment based on the								
determination of proved reserves			(107)		(631)		(149)	
Divestments/Other			(106)		(344)		40	
Ending balance at December 31			2,707		2,679		2,881	
Ending balance attributed to equity companies included above			13		3		-	

Period end capitalized suspended exploratory well costs:

			2013		2012		2011	
			<i>(millions of dollars)</i>					
Capitalized for a period of one year or less			293		866		310	
Capitalized for a period of between one and five years			1,705		1,176		1,922	
Capitalized for a period of between five and ten years			470		401		409	
Capitalized for a period of greater than ten years			239		236		240	
Capitalized for a period greater than one year - subtotal			2,414		1,813		2,571	
Total			2,707		2,679		2,881	

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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.

			2013		2012		2011
Number of projects with first capitalized well drilled in the preceding 12 months			8		10		4
Number of projects that have exploratory well costs capitalized for a period							
	of greater than 12 months		50		45		58
	Total		58		55		62

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Of the 50 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2013, 17 projects have drilling in the preceding 12 months or exploratory activity planned in the next two years, while the remaining 33 projects are those with completed exploratory activity progressing toward development. The table below provides additional detail for those 33 projects, which total \$925 million.

Country/Project	Dec. 31,		Years	Comment
	2013		Drilled	
<i>(millions of dollars)</i>				
Angola				
- Kaombo Split Hub	155		2003 - 2012	Multiple deepwater oil discoveries, progressing development plan.
- Perpetua-Zinia-Acacia	15		2008 - 2009	Oil field near Pazflor development, awaiting capacity in existing/planned infrastructure.
Australia				
- East Pilchard	9		2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Longtom	13		2010	Gas field near Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Remora	42		2010	Gas field near Marlin development, awaiting capacity in existing/planned infrastructure.
Indonesia				
- Alas Tua West	16		2010	Evaluating development plan to tie into planned production facilities.
- Cepu Gas	28		2008 - 2011	Development activity under way, while continuing commercial discussions with the government.
- Kedung Keris	11		2011	Evaluating development plan to tie into planned production facilities.
- Natuna	118		1981 - 1983	Development activity under way, while continuing discussions with the government on contract terms pursuant to executed Heads of Agreement.
Kazakhstan				
- Kairan	53		2004 - 2007	Evaluating commercialization and field development alternatives, while continuing discussions with the government regarding the development plan.
Malaysia				
- Besar	18		1992 - 2010	Gas field off the east coast of Malaysia; progressing development plan.

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- Bindu		2		1995	Awaiting capacity in existing/planned infrastructure.
Nigeria					
- Bolia		15		2002 - 2006	Evaluating development plan, while continuing discussions with the government regarding regional hub strategy.
- Bosi		79		2002 - 2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Bosi Central		16		2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Owowo		50		2009 - 2012	Continuing discussions with the government regarding contract terms.
- Pegi		32		2009	Awaiting capacity in existing/planned infrastructure.
- Uge		18		2005 - 2008	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
- Other (4 projects)		14		2002	Evaluating and pursuing development of several additional discoveries.
Norway					
- Gamma		19		2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- Other (5 projects)		21		2008 - 2010	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.
- P'nyang		58		2012	Working on development plans to tie into planned LNG facilities.
Republic of Congo					
- Mer Tres Profonde Sud		56		2000 - 2007	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
United Kingdom					
- Phyllis		8		2004	Evaluating development plan for tieback to existing production facilities.
United States					
- Tip Top		31		2009	Evaluating development concept and requisite facility upgrades.
Total 2013 (33 projects)		925			

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Net income attributable to ExxonMobil (<i>millions of dollars</i>)		32,580		44,880	41,060
Weighted average number of common shares outstanding (<i>millions of shares</i>)		4,419		4,628	4,870
Earnings per common share (<i>dollars</i>)		7.37		9.70	8.43
Earnings per common share - assuming dilution					
Net income attributable to ExxonMobil (<i>millions of dollars</i>)		32,580		44,880	41,060
Weighted average number of common shares outstanding (<i>millions of shares</i>)		4,419		4,628	4,870
Effect of employee stock-based awards		-		-	5
Weighted average number of common shares outstanding - assuming dilution		4,419		4,628	4,875
Earnings per common share - assuming dilution (<i>dollars</i>)		7.37		9.70	8.42
Dividends paid per common share (<i>dollars</i>)		2.46		2.18	1.85

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

13. 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, excluding capitalized lease obligations, was \$6.8 billion and \$8.0 billion at December 31, 2013, and 2012, respectively, as compared to recorded book values of \$6.5 billion and \$7.5 billion at December 31, 2013, and 2012, respectively.

The fair value of long-term debt by hierarchy level at December 31, 2013, is: Level 1 \$5,756 million; Level 2 \$967 million; and Level 3 \$64 million. Level 1 represents quoted prices in active markets. Level 2 includes debt whose fair value is based upon a publicly available index. Level 3 involves using internal data augmented by relevant market indicators if available.

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.

The estimated fair value of derivative instruments outstanding and recorded on the balance sheet was a net asset of \$1 million at year-end 2013 and a net asset of \$2 million at year-end 2012. Assets and liabilities associated with derivatives are usually recorded either in "Other current assets" or "Accounts payable and accrued liabilities."

The Corporation's fair value measurement of its derivative instruments use either Level 1 (observable quoted prices on active exchanges) or Level 2 (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) inputs.

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of \$(7) million, \$(23) million and \$131 million during 2013, 2012 and 2011, respectively. Income statement effects associated with derivatives are usually recorded either in "Sales and other operating revenue" or "Crude oil and product purchases."

The Corporation believes 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

14. Long-Term Debt

At December 31, 2013, long-term debt consisted of \$6,542 million due in U.S. dollars and \$349 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 \$1,034 million, which matures within one year and is included in current liabilities. The amounts of long-term debt maturing in each of the four years after December 31, 2014, in millions of dollars, are: 2015 – \$782; 2016 – \$513; 2017 – \$857; and 2018 – \$900.

Summarized long-term debt at year-end 2013 and 2012 are shown in the table below:

			2013	2012
			<i>(millions of dollars)</i>	
	XTO Energy Inc. (1)			
		4.900% senior note due 2014	-	254
		5.000% senior note due 2015	132	135
		5.300% senior note due 2015	243	249
		5.650% senior note due 2016	212	217
		6.250% senior note due 2017	489	501
		5.500% senior note due 2018	389	396
		6.500% senior note due 2018	485	495
		6.100% senior note due 2036	200	201
		6.750% senior note due 2037	312	314
		6.375% senior note due 2038	238	240
	Mobil Services (Bahamas) Ltd. (2)			
		Variable note due 2034	-	311
	Mobil Producing Nigeria Unlimited (3)			
		Variable notes due 2014-2019	742	751
	Esso (Thailand) Public Company Ltd. (4)			
		Variable notes due 2014-2017	177	414
	Mobil Corporation			
		8.625% debentures due 2021	249	249
	Industrial revenue bonds due 2014-2051 (5)		2,527	2,690
	Other U.S. dollar obligations (6)		112	74
	Other foreign currency obligations		9	6
	Capitalized lease obligations (7)		375	431
	Total long-term debt		6,891	7,928

- (1) *Includes premiums of \$271 million in 2013 and \$326 million in 2012.*
- (2) *Average effective interest rate of 0.5% in 2012.*
- (3) *Average effective interest rate of 4.6% in 2013 and 4.6% in 2012.*
- (4) *Average effective interest rate of 3.3% in 2013 and 3.5% in 2012.*
- (5) *Average effective interest rate of 0.1% in 2013 and 0.1% in 2012.*
- (6) *Average effective interest rate of 4.4% in 2013 and 2.7% in 2012.*
- (7) *Average imputed interest rate of 7.8% in 2013 and 7.6% in 2012.*

The Corporation has long-term committed lines of credit of \$0.6 billion which were unused as of December 31, 2013. Of this total, \$0.5 billion supports commercial paper programs.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of award. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. 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. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, 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 2013, remaining shares available for award under the 2003 Incentive Program were 117 million.

Restricted Stock and Restricted Stock Units. Awards totaling 9,729 thousand, 10,017 thousand, and 10,533 thousand of restricted (nonvested) common stock and restricted (nonvested) common stock units were granted in 2013, 2012 and 2011, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. 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 and units 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 and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of 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.

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.

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2013.

	2013					
				Weighted Average		
				Grant-Date		
Restricted stock and units outstanding	Shares			Fair Value per Share		
	<i>(thousands)</i>			<i>(dollars)</i>		
Issued and outstanding at January 1	46,451				73.94	
2012 award issued in 2013	10,016				87.24	
Vested	(11,068)				68.15	
Forfeited	(192)				77.22	
Issued and outstanding at December 31	45,207				78.29	
Value of restricted stock and units		2013		2012		2011
Grant price <i>(dollars)</i>		94.47		87.24		79.52

Value at date of grant:		<i>(millions of dollars)</i>				
Restricted stock and units settled in stock		843		797		766
Units settled in cash		76		77		72
Total value		919		874		838

As of December 31, 2013, there was \$2,269 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.5 years. The compensation cost charged against income for the restricted stock and restricted stock units was \$854 million, \$854 million and \$793 million for 2013, 2012 and 2011, respectively. The income tax benefit recognized in income related to this compensation expense was \$78 million, \$79 million and \$73 million for the same periods, respectively. The fair value of shares and units vested in 2013, 2012 and 2011 was \$1,040 million, \$926 million and \$801 million, respectively. Cash payments of \$67 million, \$66 million and \$46 million for vested restricted stock units settled in cash were made in 2013, 2012 and 2011, respectively.

Stock Options. The Corporation has not granted any stock options under the 2003 Incentive Program and all stock options granted under the prior program were exercised by the end of 2011. In 2010, the Corporation granted 12,393 thousand of converted XTO stock options of which 1,506 thousand stock options, with an average exercise price of \$85.57, were outstanding as of December 31, 2013.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

16. Litigation and Other Contingencies

Litigation. A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. 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. For purposes of our contingency disclosures, "significant" includes material matters as well as other matters which management believes should be disclosed. 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 material adverse effect upon the Corporation's operations, financial condition, or financial statements taken as a whole.

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2013, for guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure.

						Dec. 31, 2013			
				Equity Company		Other Third-Party			
				Obligations (1)		Obligations		Total	
						<i>(millions of dollars)</i>			
Guarantees									
	Debt-related			3,086			46		3,132
	Other			2,939			4,507		7,446
	Total			6,025			4,553		10,578
<i>(1) ExxonMobil share.</i>									

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					
	2014	2015-2018	2019 and Beyond	Total		
	<i>(millions of dollars)</i>					
Unconditional purchase obligations (1)	144	629	463	1,236		

(1) Undiscounted obligations of \$1,236 million mainly pertain to pipeline throughput agreements and include \$457 million of obligations to equity companies. The present value of these commitments, which excludes imputed interest of \$267 million, totaled \$969 million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. ExxonMobil's remaining net book investment in Cerro Negro producing assets is about \$750 million.

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 was held in February 2012. At this time, the net impact of these matters on the Corporation's consolidated financial results cannot be reasonably estimated. Regardless, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition.

An affiliate of ExxonMobil is one of the Contractors under a Production Sharing Contract (PSC) with the Nigerian National Petroleum Corporation (NNPC) covering the Erha block located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the block and owns a 56.25 percent interest under the PSC. The Contractors are in dispute with NNPC regarding NNPC's lifting of crude oil in excess of its entitlement under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuja, Nigeria, under the Nigerian Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholding the Contractors' position in all material respects and awarding damages to the Contractors jointly in an amount of approximately \$1.8 billion plus \$234 million in accrued interest. The Contractors petitioned a Nigerian federal court for enforcement of the award, and NNPC petitioned the same court to have the award set aside. On May 22, 2012, the court set aside the award. The Contractors have appealed that judgment. In June 2013, the Contractors filed a lawsuit against NNPC in the Nigerian federal high court in order to preserve their ability to seek enforcement of the PSC in the courts if necessary. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, regardless of the outcome of enforcement proceedings, the Corporation does not expect the proceedings to have a material effect upon the Corporation's operations or financial condition.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

17. 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.				
		2013	2012		2013	2012		2013	2012
<i>(percent)</i>									
Weighted-average assumptions used to determine									
	benefit obligations at December 31								
	Discount rate	5.00	4.00		4.30	3.80		5.00	4.00
	Long-term rate of compensation increase	5.75	5.75		5.40	5.50		5.75	5.75
<i>(millions of dollars)</i>									
Change in benefit obligation									
	Benefit obligation at January 1	19,779	17,035		28,670	29,068		9,058	7,880
	Service cost	801	665		697	648		176	134
	Interest cost	749	820		1,076	1,145		352	380
	Actuarial loss/(gain)	(1,520)	2,553		(1,454)	2,335		(1,267)	1,035
	Benefits paid (1) (2)	(2,520)	(1,294)		(1,311)	(1,330)		(511)	(476)
	Foreign exchange rate changes	-	-		(284)	651		(43)	13
	Japan restructuring and other divestments	-	-		(77)	(3,952)		-	-
	Plan amendments, other	15	-		40	105		103	92
	Benefit obligation at December 31	17,304	19,779		27,357	28,670		7,868	9,058
	Accumulated benefit obligation at December 31	13,989	15,902		23,949	24,345		-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2013 and 2012, other postretirement benefits paid are net of \$20 million and \$23 million of Medicare subsidy receipts, respectively.

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the discount rate 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 a health care cost trend rate of 4.5 percent in 2015 and subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by \$68 million and the postretirement benefit obligation by \$734 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by \$53 million and the postretirement benefit obligation by \$597 million.

		Pension Benefits						Other Postretirement Benefits		
		U.S.			Non-U.S.					
		2013	2012		2013	2012		2013	2012	
<i>(millions of dollars)</i>										
Change in plan assets										
	Fair value at January 1	12,632	10,656		18,090	17,117		581		538
	Actual return on plan assets	617	1,457		1,604	1,541		64		65
	Foreign exchange rate changes	-	-		(270)	462		-		-
	Company contribution	101	1,560		919	1,604		35		38
	Benefits paid (1)	(2,171)	(1,041)		(869)	(922)		(60)		(60)
	Japan restructuring and other divestments	-	-		(45)	(1,696)		-		-
	Other	11	-		(146)	(16)		-		-
	Fair value at December 31	11,190	12,632		19,283	18,090		620		581

(1) Benefit payments for funded plans.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.		
		2013		2012		2013	2012
		<i>(millions of dollars)</i>					
Assets in excess of/(less than) benefit obligation							
	Balance at December 31						
	Funded plans	(3,547)		(4,438)		(941)	(3,247)
	Unfunded plans	(2,567)		(2,709)		(7,133)	(7,333)
Total		(6,114)		(7,147)		(8,074)	(10,580)

The authoritative guidance for defined benefit pension and other postretirement 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.			Benefits	
		2013		2012		2013	2012	2013	2012
		<i>(millions of dollars)</i>							
Assets in excess of/(less than) benefit obligation									
	Balance at December 31 <i>(1)</i>	(6,114)		(7,147)		(8,074)	(10,580)	(7,248)	(8,477)
Amounts recorded in the consolidated balance sheet consist of:									
	Other assets	1		1		201	49	-	-
	Current liabilities	(275)		(279)		(358)	(352)	(359)	(356)

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	Postretirement benefits reserves		(5,840)		(6,869)		(7,917)		(10,277)		(6,889)		(8,121)
Total recorded			(6,114)		(7,147)		(8,074)		(10,580)		(7,248)		(8,477)
Amounts recorded in accumulated other													
comprehensive income consist of:													
	Net actuarial loss/(gain)		4,780		7,451		7,943		10,904		1,603		3,132
	Prior service cost		60		67		665		758		65		85
Total recorded in accumulated other													
	comprehensive income		4,840		7,518		8,608		11,662		1,668		3,217

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 percentages and the long-term return assumption for each asset class.

										Other									
Pension Benefits										Postretirement									
U.S.										Non-U.S.			Benefits						
2013										2012			2011						
Weighted-average assumptions used to																			
determine net periodic benefit cost for																			
years ended December 31										<i>(percent)</i>									
Discount rate										4.00	5.00	5.50	3.80	4.00	4.80	4.00	5.00	5.50	
Long-term rate of return on funded assets										7.25	7.25	7.50	6.40	6.60	6.80	7.25	7.25	7.50	
Long-term rate of compensation increase										5.75	5.75	5.25	5.50	5.40	5.20	5.75	5.75	5.25	
Components of net periodic benefit cost										<i>(millions of dollars)</i>									
Service cost										801	665	546	697	648	574	176	134	121	
Interest cost										749	820	792	1,076	1,145	1,267	352	380	393	
Expected return on plan assets										(835)	(789)	(769)	(1,128)	(1,109)	(1,168)	(41)	(38)	(41)	
Amortization of actuarial loss/(gain)										646	576	485	852	844	647	228	170	162	
Amortization of prior service cost										7	7	9	117	117	103	21	34	35	
Net pension enhancement and curtailment/settlement cost (1)										723	333	286	22	1,540	34	-	-	-	
Net periodic benefit cost										2,091	1,612	1,349	1,636	3,185	1,457	736	680	670	

(1)		<i>Non-U.S. net pension enhancement and curtailment/settlement cost for 2012 includes \$1,420 million (on a consolidated-company, before-tax basis) of accumulated other comprehensive income for the postretirement benefit reserves adjustment that was recycled into earnings and included in the Japan restructuring gain reported in "Other income".</i>									
Changes in amounts recorded in accumulated											
other comprehensive income:											
Net actuarial loss/(gain)		(1,302)	1,885	2,218	(1,938)	1,906	4,133	(1,290)	1,008	468	
Amortization of actuarial (loss)/gain		(1,369)	(909)	(771)	(874)	(2,384)	(681)	(228)	(170)	(162)	
Prior service cost/(credit)		-	-	-	30	71	187	-	-	-	
Amortization of prior service (cost)/credit		(7)	(7)	(9)	(117)	(117)	(103)	(21)	(34)	(35)	
Foreign exchange rate changes		-	-	-	(155)	271	(90)	(10)	3	-	
Total recorded in other comprehensive income		(2,678)	969	1,438	(3,054)	(253)	3,446	(1,549)	807	271	
Total recorded in net periodic benefit cost and											
other comprehensive income, before tax		(587)	2,581	2,787	(1,418)	2,932	4,903	(813)	1,487	941	

Costs for defined contribution plans were \$392 million, \$382 million and \$378 million in 2013, 2012 and 2011, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

		Total Pension and Other Postretirement Benefits			
		2013	2012	2011	
		<i>(millions of dollars)</i>			
(Charge)/credit to other comprehensive income, before tax					
	U.S. pension	2,678	(969)	(1,438)	
	Non-U.S. pension	3,054	253	(3,446)	
	Other postretirement benefits	1,549	(807)	(271)	
Total (charge)/credit to other comprehensive income, before tax		7,281	(1,523)	(5,155)	
(Charge)/credit to income tax (see Note 4)		(2,336)	393	1,495	
(Charge)/credit to investment in equity companies		49	(49)	(30)	
(Charge)/credit to other comprehensive income including noncontrolling					
	interests, after tax	4,994	(1,179)	(3,690)	
Charge/(credit) to equity of noncontrolling interests		(279)	(124)	288	
(Charge)/credit to other comprehensive income attributable to ExxonMobil		4,715	(1,303)	(3,402)	

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 percentages. The target asset allocation for the U.S. benefit plans is 50 percent equity securities and 50 percent debt securities. The target asset allocation for the non-U.S. plans in aggregate is 49 percent equity securities and 51 percent debt securities. 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 percent and 3 percent, 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2013 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					Fair Value Measurement						
		at December 31, 2013, Using:					at December 31, 2013, Using:						
		Quoted					Quoted						
		Prices					Prices						
		in Active	Significant				in Active	Significant					
		Markets for	Other	Significant			Markets for	Other	Significant				
		Identical	Observable	Unobservable			Identical	Observable	Unobservable				
		Assets	Inputs	Inputs			Assets	Inputs	Inputs				
		(Level 1)	(Level 2)	(Level 3)		Total	(Level 1)	(Level 2)	(Level 3)		Total		
		<i>(millions of dollars)</i>											
Asset category:													
	Equity securities												
	U.S.	-	2,514	(1)	-	2,514	-	3,046	(1)	-	3,046		
	Non-U.S.	-	2,622	(1)	-	2,622	294	(2)	5,608	(1)	-	5,902	
	Private equity	-	-		523	(3)	523	-	-		502	(3)	502
	Debt securities												
	Corporate	-	3,430	(4)	-	3,430	-	2,125	(4)	-	2,125		
	Government	-	2,056	(4)	-	2,056	272	(5)	7,100	(4)	-	7,372	
	Asset-backed	-	6	(4)	-	6	-	103	(4)	-	103		
	Real estate funds	-	-		-	-	-	-		136	(6)	136	
	Cash	-	27	(7)	-	27	57		20	(8)	-	77	
	Total at fair value	-	10,655		523	11,178	623		18,002		638	19,263	
	Insurance contracts												
	at contract value					12						20	
	Total plan assets					11,190						19,283	

(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 real estate funds, fair value is based on appraised values developed using comparable market transactions.*
- (7) *For cash balances held in the form of short-term fund units that are redeemable at the measurement date, the fair value is treated as a Level 2 input.*
- (8) *For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a Level 2 input.*

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

		Other Postretirement						
		Fair Value Measurement						
		at December 31, 2013, Using:						
		Quoted						
		Prices						
		in Active	Significant					
		Markets	Other		Significant			
		for	Observable		Unobservable			
		Identical	Inputs		Inputs			
		Assets	(Level 2)		(Level 3)		Total	
		(Level 1)						
		<i>(millions of dollars)</i>						
Asset category:								
	Equity securities							
	U.S.	-	157	(1)	-			157
	Non-U.S.	-	149	(1)	-			149
	Private equity	-	-		9	(2)		9
	Debt securities							
	Corporate	-	129	(3)	-			129
	Government	-	168	(3)	-			168
	Asset-backed	-	4	(3)	-			4
	Cash	-	4		-			4
Total at fair value		-	611		9			620

(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.

The change in the fair value in 2013 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

		2013
--	--	-------------

	Pension						Other	
	U.S.			Non-U.S.			Postretirement	
	Private			Private		Real		Private
	Equity			Equity		Estate		Equity
	<i>(millions of dollars)</i>							
Fair value at January 1	489			448		293		7
Net realized gains/(losses)	(1)			11		(13)		-
Net unrealized gains/(losses)	86			57		10		3
Net purchases/(sales)	(51)			(14)		(154)		(1)
Fair value at December 31	523			502		136		9

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2012 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							Fair Value Measurement							
		at December 31, 2012, Using:							at December 31, 2012, Using:							
		Quoted							Quoted							
		Prices							Prices							
		in Active	Significant						in Active	Significant						
		Markets for	Other	Significant					Markets for	Other	Significant					
		Identical	Observable	Unobservable					Identical	Observable	Unobservable					
		Assets	Inputs	Inputs					Assets	Inputs	Inputs					
		(Level 1)	(Level 2)	(Level 3)					(Level 1)	(Level 2)	(Level 3)					