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

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 444-1000

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, without par value (4,321,238,544 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 x 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 x

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 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 requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File re 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 re to submit and post such files). Yes x 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, 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 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. S definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x 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 x

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 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 exc $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 oper market products in the United States and most other countries of the world. Their principal business is energy, involving exploration fo production of, crude oil and natural gas, manufacture of petroleum products and transportation and sale of crude oil, natural gas and petro products. ExxonMobil is a major manufacturer and marketer of commodity petrochemicals, including olefins, aromatics, polyethylen polypropylene plastics and a wide variety of specialty products. ExxonMobil also has interests in electric power generation facilities. Affi of ExxonMobil conduct extensive research programs in support of these businesses.

Exxon Mobil Corporation has several divisions and hundreds of affiliates, many with names that include *ExxonMobil*, *Exxon*, *Esso*, or *XTO*. For convenience and simplicity, in this report the terms *ExxonMobil*, *Exxon*, *Esso*, *Mobil* and *XTO*, as well as terms like *Corpor Company*, *our*, *we* and *its*, are sometimes used as abbreviated references to specific affiliates or groups of affiliates. The precise me 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 c water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels as w projects to monitor and reduce nitrogen oxide, sulfur oxide, and greenhouse gas emissions and expenditures for asset retirement obligat Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2013 worldwide environmental expend for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $6.0 billion, of $3.5 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to remain i 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 industr supplying the energy, fuel and chemical needs of both industrial and individual consumers. The Corporation competes with other firms sale or purchase of needed goods and services in many national and international markets and employs all methods of competition whic lawful and appropriate for such purposes.

Operating data and industry segment information for the Corporation are contained in the Financial Section of this report unde following: "Quarterly Information", "Note 18: Disclosures about Segments and Related Information" and "Operating Summary". Inform on oil and gas reserves is contained in the "Oil and Gas Reserves" part of the "Supplemental Information on Oil and Gas Exploratio 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 prog designed to meet the needs identified in each of our business segments. Information on Company-sponsored research and develop spending is contained in "Note 3: Miscellaneous Financial Information" of the Financial Section of this report. ExxonMobil approximately 11 thousand active patents worldwide at the end of 2013. For technology licensed to third parties, revenues to approximately $195 million in 2013. Although technology is an important contributor to the overall operations and results of our Compan 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, respect Regular employees are defined as active executive, management, professional, technical and wage employees who work full time or par for the Corporation and are covered by the Corporation's benefit plans and programs. Regular employees do not include employees company-operated retail sites (CORS). The number of CORS employees was 9.8 thousand, 11.1 thousand and 17.0 thousand at years 2013, 2012 and 2011, respectively.

Information concerning the source and availability of raw materials used in the Corporation's business, the extent of seasonality i business, the possibility of renegotiation of profits or termination of contracts at the election of governments and risks attendant to fo 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 repo 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 available through our website as soon as reasonably practical after we electronically file or furnish the reports to the Securities and Excl Commission. Also available on the Corporation's website are the Company's Corporate Governance Guidelines and Code of Ethic Business Conduct, as well as the charters of the audit, compensation and nominating committees of the Board of Directors. Information c 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 busin Many of these risk factors are not within the Company’s control and could adversely affect our business, our financial and operating resu 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 be significantly affected by changes in oil, gas and petrochemical prices and by changes in margins on refined products. Oil, gas, petroche and product prices and margins in turn depend on local, regional and global events or conditions that affect supply and demand for the rel commodity.

Economic conditions. The demand for energy and petrochemicals correlates closely with general economic growth rates. The occurren recessions or other periods of low or negative economic growth will typically have a direct adverse impact on our results. Other factor affect general economic conditions in the world or in a major region, such as changes in population growth rates, periods of civil u government austerity programs, or currency exchange rate fluctuations, can also impact the demand for energy and petrochemicals. Sove debt downgrades, defaults, inability to access debt markets due to credit or legal constraints, liquidity crises, the breakup or restructuri fiscal, monetary, or political systems such as the European Union, and other events or conditions that impair the functioning of fina markets and institutions also pose risks to ExxonMobil, including risks to the safety of our financial assets and to the ability of our partner 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 re include technological improvements in energy efficiency; seasonal weather patterns, which affect the demand for energy associated heating and cooling; increased competitiveness of alternative energy sources that have so far generally not been competitive with oil an without the benefit of government subsidies or mandates; and changes in technology or consumer preferences that alter fuel choices, su toward alternative fueled vehicles.

Other supply-related factors. Commodity prices and margins also vary depending on a number of factors affecting supply. For exa increased supply from the development of new oil and gas supply sources and technologies to enhance recovery from existing sources te reduce commodity prices to the extent such supply increases are not offset by commensurate growth in demand. Similarly, increases in ind refining or petrochemical manufacturing capacity tend to reduce margins on the affected products. World oil, gas, and petrochemical s levels can also be affected by factors that reduce available supplies, such as adherence by member countries to OPEC production quota the occurrence of wars, hostile actions, natural disasters, disruptions in competitors’ operations, or unexpected unavailability of distrib channels that may disrupt supplies. Technological change can also alter the relative costs for competitors to find, produce, and refine oi 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, infl currency exchange rates, and other local or regional market conditions. We generally do not use financial instruments to hedge m 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 develop altogether. Restrictions on foreign investment in the oil and gas sector tend to increase in times of high commodity prices, when na governments may have less need of outside sources of private capital. Many countries also restrict the import or export of certain pro 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 c countries, or restricting the kind of business that may be conducted. Such restrictions may provide a competitive advantage to our non 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 regu frameworks for oil and gas development. Lack of legal certainty exposes our operations to increased risk of adverse or unpredictable actio government officials, and also makes it more difficult for us to enforce our contracts. In some cases these risks can be partially offs agreements to arbitrate disputes in an international forum, but the adequacy of this remedy may still depend on the local legal syste enforce an award.

Regulatory and litigation risks. Even in countries with well-developed legal systems where ExxonMobil does business, we remain ex 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 bu 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 comm 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 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 larg unpredictable punitive damage awards may occur, or by government enforcement proceedings alleging non-compliance with applicable la regulations.

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

Climate change and greenhouse gas restrictions. Due to concern over the risk of climate change, a number of countries have adopted, considering the adoption of, regulatory frameworks to reduce greenhouse gas emissions. These include adoption of cap and trade reg carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates for renewable energy. These requirements make our products more expensive, lengthen project implementation times, and reduce demand for hydrocarbons, as well as shift hydroc demand toward relatively lower-carbon sources such as natural gas. Current and pending greenhouse gas regulations may also increas 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 alter energy sources or are mandating the use of specific fuels or technologies. Governments are also promoting research into new technolog reduce the cost and increase the scalability of alternative energy sources. We are conducting our own research efforts into alternative e such as through sponsorship of the Global Climate and Energy Project at Stanford University and research into liquid products from alga biomass that can be further converted to transportation fuels. Our future results may depend in part on the success of our research effort on our ability to adapt and apply the strengths of our current business model to providing the energy products of the future in a 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 factors that are at least in part within our control. The extent to which we manage these factors will impact our performance relati competition. For projects in which we are not the operator, we depend on the management effectiveness of one or more co-venturers who do not control.

Exploration and development program. Our ability to maintain and grow our oil and gas production depends on the success c exploration and development efforts. Among other factors, we must continuously improve our ability to identify the most promising res 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- capital intensive projects. These projects in turn require a high degree of project management expertise to maximize efficiency. Specific f that can affect the performance of major projects include our ability to: negotiate successfully with joint venturers, partners, governm suppliers, customers, or others; model and optimize reservoir performance; develop markets for project outputs, whether through long contracts or the development of effective spot markets; manage changes in operating conditions and costs, including costs of third equipment or services such as drilling rigs and shipping; prevent, to the extent possible, and respond effectively to unforeseen tec difficulties that could delay project startup or cause unscheduled project downtime; and influence the performance of project operators 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 any government payment transparency reports.

Operational efficiency. An important component of ExxonMobil’s competitive performance, especially given the commodity-based natu many of our businesses, is our ability to operate efficiently, including our ability to manage expenses and improve production yields ongoing basis. This requires continuous management focus, including technology improvements, cost control, productivity enhancem 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 an need for continuous efficiency improvement, ExxonMobil’s research and development organizations must be successful and able to adap changing market and policy environment.

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

Business risks also include the risk of cybersecurity breaches. If our systems for protecting against cybersecurity risks prove not sufficient, ExxonMobil could be adversely affected such as by having its business systems compromised, its proprietary information al 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 exa hurricanes may damage our offshore production facilities or coastal refining and petrochemical plants in vulnerable areas. Our abil mitigate the adverse impacts of these events depends in part upon the effectiveness of our rigorous disaster preparedness and res 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 c report are forward-looking statements. Actual future results, including project completion dates, production rates, capital expenditures, 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 subsidiarie equity companies. The Corporation has reported proved reserves on the basis of the average of the first-day-of-the-month price for each r during the last 12-month period. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. No discovery or other favorable or adverse event has occurred since December 31, 2013, that would cause a significant change in the esti proved reserves as of that date.

	Crude Oil	Natural Gas Liquids	Bitumen	Synthetic Oil	Natural Gas	Oil-Equiva Basis
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million bl*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,212	257	-	-	14,655	3
Canada/South America *(1)*	111	15	1,810	579	664	2
Europe	210	39	-	-	2,189	
Africa	765	180	-	-	779	1
Asia	1,525	138	-	-	5,241	2
Australia/Oceania	56	49	-	-	969	
Total Consolidated	3,879	678	1,810	579	24,497	11
Equity Companies						
United States	258	10	-	-	197	
Europe	27	-	-	-	6,852	1
Asia	902	390	-	-	17,288	4
Total Equity Company	1,187	400	-	-	24,337	5
Total Developed	5,066	1,078	1,810	579	48,834	16
Undeveloped						
Consolidated Subsidiaries						
United States	796	272	-	-	11,365	2
Canada/South America *(1)*	173	4	1,820	-	571	2
Europe	35	16	-	-	621	
Africa	428	21	-	-	88	
Asia	638	-	-	-	493	
Australia/Oceania	99	32	-	-	6,546	1
Total Consolidated	2,169	345	1,820	-	19,684	7
Equity Companies						
United States	72	5	-	-	84	
Europe	1	-	-	-	2,032	
Asia	243	51	-	-	1,226	
Total Equity Company	316	56	-	-	3,342	
Total Undeveloped	2,485	401	1,820	-	23,026	8
Total Proved Reserves	7,551	1,479	3,630	579	71,860	25

(1) South America includes proved developed reserves of 0.2 million barrels of crude oil and natural gas liquids and 44 billion cubic f natural gas and proved undeveloped reserves of 0.1 million barrels of crude oil and natural gas liquids and 10 billion cubic feet of n gas.

In the preceding reserves information, consolidated subsidiary and equity company reserves are reported separately. However, the Corpo 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 over the period 2014-2018. However, actual volumes will vary from year to year due to the timing of individual project start-ups, opera outages, reservoir performance, regulatory changes, asset sales, weather events, price effects on production sharing contracts and other f 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 rig technical evaluations, commercial and market assessments and detailed analysis of well and reservoir information such as flow rate reservoir pressure declines. Furthermore, the Corporation only records proved reserves for projects which have received significant fu commitments by management made toward the development of the reserves. Although the Corporation is reasonably certain that p reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of develo 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 appro geological, engineering and production data, utilizing well-established technologies that have been demonstrated in the field to yield repe and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and perform information. The data utilized also included subsurface information obtained through indirect measurements including high-quality 2-D a D seismic data, calibrated with available well control information. The tools used to interpret the data included proprietary seismic proce 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 in 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. Pr responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Comm (SEC) rules and regulations, review of annual changes in reserves estimates, and the reporting of ExxonMobil's proved reserves. This also maintains the official company reserves estimates for ExxonMobil's proved reserves of crude and natural gas liquids, bitumen, syn oil and natural gas. In addition, the group provides training to personnel involved in the reserves estimation and reporting process ExxonMobil and its affiliates. The Manager of the Global Reserves group has more than 30 years of experience in reservoir engineerin reserves assessment and has a degree in Engineering. He is an active member of the Society of Petroleum Engineers (SPE) and previ served on the SPE Oil and Gas Reserves Committee. The group is managed by and staffed with individuals that have an average of mor 20 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves und SEC guidelines. This group includes individuals who hold advanced degrees in either Engineering or Geology. Several members of the 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, incl limitations on database access and update capabilities, are in place to ensure data integrity within this central database. An annual revi the system's controls is performed by internal audit. Key components of the reserves estimation process include technical evaluation analysis of well and field performance and a rigorous peer review. No changes may be made to the reserves estimates in the central dat including additions of any new initial reserves estimates or subsequent revisions, unless these changes have been thoroughly review evaluated by duly authorized personnel within the operating organization. In addition, changes to reserves estimates that exceed c thresholds require further review and approval of the appropriate level of management within the operating organization before the ch may be made in the central database. Endorsement by the Global Reserves group for all proved reserves changes is a mandatory compon 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 p undeveloped. This represents 34 percent of the 25.2 GOEB reported in proved reserves. This compares to the 9.9 GOEB of p undeveloped reserves reported at the end of 2012. The net decrease is primarily due to project startups in Canada and Kazakhstan. Durir year, ExxonMobil conducted development activities in over 100 fields that resulted in the transfer of approximately 1.9 GOEB from p undeveloped to proved developed reserves by year-end. The largest transfers were related to Kearl Initial Development startup and nev steam injection in the Cold Lake field in Canada, Kashagan field startup in Kazakhstan and the Groningen compression assessment i Netherlands.

One of ExxonMobil's requirements for reporting proved reserves is that management has made significant funding commitments towa development of the reserves. ExxonMobil has a disciplined investment strategy and many major fields require long lead-time in order developed. Development projects typically take two to four years from the time of first recording of proved reserves to the start of produ of these reserves. However, the development time for large and complex projects can exceed five years. During 2013, discoverie extensions related to new projects added approximately 0.7 GOEB of proved undeveloped reserves. The largest of these additions were r to planned drilling in the United States and Upper Zakum field expansion in Abu Dhabi. Overall, investments of $25.3 billion were ma the Corporation during 2013 to progress the development of reported proved undeveloped reserves, including $22.7 billion for oil an producing activities and an additional $2.6 billion for other non-oil and gas producing activities such as the construction of su infrastructure and other related facilities that were undertaken to progress the development of proved undeveloped reserves. These invest 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 rem undeveloped for five years or more primarily due to constraints on the capacity of infrastructure, the pace of co-venturer/government fur as well as the time required to complete development for very large projects. The Corporation is reasonably certain that these proved res will be produced; however, the timing and amount recovered can be affected by a number of factors including completion of develop projects, reservoir performance, regulatory approvals, and significant changes in long-term oil and gas price levels. Of the proved undeve reserves that have been reported for five or more years, 91 percent are contained in the aforementioned countries. The largest of th related to LNG/Gas projects in Australia and Papua New Guinea, where construction of the initial development is under way. In Kazak the proved undeveloped reserves are related to the remainder of the initial development of the offshore Kashagan field which is included North Caspian Production Sharing Agreement and the Tengizchevroil joint venture which includes a production license in the Tengiz – Kc field complex. The Tengizchevroil joint venture is producing, and proved undeveloped reserves will continue to move to proved develop approved development phases progress. In the Netherlands, the Groningen gas field has proved undeveloped reserves reported that are r to installation of future stages of compression. These reserves will move to proved developed when the additional stages of compressic 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	
			(thousands of barrels daily)			
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NC
Consolidated Subsidiaries						
United States	283	85	274	81	280	
Canada/South America *(1)*	57	10	49	10	53	
Europe	157	27	170	33	219	
Africa	451	18	472	15	491	
Asia	313	30	319	43	329	
Australia/Oceania	29	19	32	18	34	
Total Consolidated Subsidiaries	1,290	189	1,316	200	1,406	
Equity Companies						
United States	61	2	61	2	65	
Europe	6	-	4	-	5	
Asia	373	68	345	65	358	
Total Equity Companies	440	70	410	67	428	
Total crude oil and natural gas liquids production	1,730	259	1,726	267	1,834	
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	
			(millions of cubic feet daily)			
Natural gas production available for sale						
Consolidated Subsidiaries						
United States	3,530		3,819		3,917	
Canada/South America *(1)*	354		362		412	
Europe	1,294		1,446		1,701	
Africa	6		17		7	
Asia	1,180		1,445		1,879	
Australia/Oceania	351		363		331	
Total Consolidated Subsidiaries	6,715		7,452		8,247	
Equity Companies						
United States	15		3		-	
Europe	1,957		1,774		1,747	
Asia	3,149		3,093		3,168	
Total Equity Companies	5,121		4,870		4,915	
Total natural gas production available for sale	11,836		12,322		13,162	
			(thousands of oil-equivalent barrels daily)			
Oil-equivalent production	4,175		4,239		4,506	

(1) South America includes liquids production for 2012 and 2011 of one thousand barrels daily for each year and natural gas produ available for sale for 2013, 2012 and 2011 of 28 million, 38 million, and 45 million cubic feet daily, respectively.

B. Production Prices and Production Costs

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

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	To
During 2013				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	93.56	98.91	106.75	108.73	106.18	107.92	1
NGL, per barrel	44.30	44.96	65.36	75.24	40.83	59.55	
Natural gas, per thousand cubic feet	2.99	2.80	10.07	2.79	4.10	4.20	
Bitumen, per barrel	-	59.63	-	-	-	-	
Synthetic oil, per barrel	-	93.96	-	-	-	-	
Average production costs, per oil-equivalent barrel - total	12.02	32.02	19.57	13.95	8.95	16.81	
Average production costs, per barrel - bitumen	-	34.30	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	50.94	-	-	-	-	
Equity Companies							
Average production prices							
Crude oil, per barrel	102.24	-	99.26	-	103.96	-	1
NGL, per barrel	42.02	-	-	-	70.90	-	
Natural gas, per thousand cubic feet	4.37	-	9.28	-	10.19	-	
Average production costs, per oil-equivalent barrel - total	22.77	-	3.79	-	1.87	-	
Total							
Average production prices							
Crude oil, per barrel	95.11	98.91	106.49	108.73	104.98	107.92	1
NGL, per barrel	44.24	44.96	65.36	75.24	61.64	59.55	
Natural gas, per thousand cubic feet	3.00	2.80	9.59	2.79	8.53	4.20	
Bitumen, per barrel	-	59.63	-	-	-	-	
Synthetic oil, per barrel	-	93.96	-	-	-	-	
Average production costs, per oil-equivalent barrel - total	12.72	32.02	12.42	13.95	4.41	16.81	
Average production costs, per barrel - bitumen	-	34.30	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	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	1
NGL, per barrel	50.32	57.84	68.08	76.63	43.65	56.85	
Natural gas, per thousand cubic feet	2.15	1.98	8.92	2.77	3.91	4.39	
Bitumen, per barrel	-	58.91	-	-	-	-	
Synthetic oil, per barrel	-	92.77	-	-	-	-	
Average production costs, per oil-equivalent barrel - total	11.14	26.94	15.06	13.35	7.27	12.11	
Average production costs, per barrel - bitumen	-	23.71	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	47.45	-	-	-	-	
Equity Companies							
Average production prices							
Crude oil, per barrel	105.02	-	104.59	-	106.59	-	1
NGL, per barrel	58.38	-	-	-	75.24	-	
Natural gas, per thousand cubic feet	3.22	-	9.66	-	9.38	-	
Average production costs, per oil-equivalent barrel - total	20.15	-	3.36	-	1.43	-	
Total							
Average production prices							
Crude oil, per barrel	96.60	98.67	110.74	111.19	108.22	112.12	1
NGL, per barrel	50.46	57.84	68.08	76.63	62.61	56.85	
Natural gas, per thousand cubic feet	2.15	1.98	9.33	2.77	7.64	4.39	
Bitumen, per barrel	-	58.91	-	-	-	-	
Synthetic oil, per barrel	-	92.77	-	-	-	-	
Average production costs, per oil-equivalent barrel - total	11.68	26.94	10.34	13.35	3.74	12.11	
Average production costs, per barrel - bitumen	-	23.71	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	47.45	-	-	-	-	

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	To
During 2011				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	98.33	104.59	109.48	110.84	107.64	115.55	1
NGL, per barrel	62.48	65.71	66.80	78.20	44.16	59.44	
Natural gas, per thousand cubic feet	3.45	3.29	9.32	2.83	3.37	3.98	
Bitumen, per barrel	-	64.65	-	-	-	-	
Synthetic oil, per barrel	-	102.80	-	-	-	-	1
Average production costs, per oil-equivalent barrel - total	11.14	23.58	13.58	14.04	6.58	12.85	
Average production costs, per barrel - bitumen	-	19.80	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	47.68	-	-	-	-	
Equity Companies							
Average production prices							
Crude oil, per barrel	105.00	-	103.23	-	105.87	-	1
NGL, per barrel	77.84	-	-	-	69.65	-	
Natural gas, per thousand cubic feet	5.08	-	8.61	-	7.78	-	
Average production costs, per oil-equivalent barrel - total	19.96	-	2.92	-	1.09	-	
Total							
Average production prices							
Crude oil, per barrel	99.57	104.59	109.33	110.84	106.72	115.55	1
NGL, per barrel	62.75	65.71	66.80	78.20	58.33	59.44	
Natural gas, per thousand cubic feet	3.45	3.29	8.96	2.83	6.14	3.98	
Bitumen, per barrel	-	64.65	-	-	-	-	
Synthetic oil, per barrel	-	102.80	-	-	-	-	1
Average production costs, per oil-equivalent barrel - total	11.68	23.58	9.85	14.04	3.41	12.85	
Average production costs, per barrel - bitumen	-	19.80	-	-	-	-	
Average production costs, per barrel - synthetic oil	-	47.68	-	-	-	-	

Average production prices have been calculated by using sales quantities from the Corporation's own production as the divisor. Av production costs have been computed by using net production quantities for the divisor. The volumes of crude oil and natural gas li (NGL) production used for this computation are shown in the oil and gas production table in section 3.A. The volumes of natural gas us the calculation are the production volumes of natural gas available for sale and are also shown in section 3.A. The natural gas available fo volumes are different from those shown in the reserves table in the "Oil and Gas Reserves" part of the "Supplemental Information on O Gas Exploration and Production Activities" portion of the Financial Section of this report due to volumes consumed or flared. Gas is conv 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
Net Productive Exploratory Wells Drilled		
Consolidated Subsidiaries		
United States	8	7
Canada/South America	4	2
Europe	-	1
Africa	2	2
Asia	-	1
Australia/Oceania	-	2
Total Consolidated Subsidiaries	14	15
Equity Companies		
United States	-	-
Europe	1	1
Asia	1	-
Total Equity Companies	2	1
Total productive exploratory wells drilled	16	16
Net Dry Exploratory Wells Drilled		
Consolidated Subsidiaries		
United States	2	2
Canada/South America	4	-
Europe	1	2
Africa	-	-
Asia	-	2
Australia/Oceania	-	1
Total Consolidated Subsidiaries	7	7
Equity Companies		
United States	1	-
Europe	-	1
Asia	-	-
Total Equity Companies	1	1
Total dry exploratory wells drilled	8	8

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

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 metho extract the crude bitumen, and then upgrade it to produce a high-quality, light (32 degrees API), sweet, synthetic crude oil. Imperia 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 Lir 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 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 metho extract the crude bitumen. Imperial Oil Limited holds a 70.96 percent interest in the joint venture and ExxonMobil Canada Properties hol other 29.04 percent. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited and a 100 percent interest in Exxonl 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 produced from open-pit mining operations, and processed through a bitumen extraction and froth treatment train. The product, a ble bitumen and diluent, is shipped to our refineries and to other third parties. Diluent is natural gas condensate or other light hydrocarbons a to the crude bitumen to facilitate transportation by pipeline. Production from the initial development began in April 2013 and production r up continued throughout the remainder of the year. During 2013, average net production at Kearl was 21 thousand barrels per day. The 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
Wells Drilling			
Consolidated Subsidiaries			
United States	1,199	480	1,099
Canada/South America	107	95	138
Europe	29	10	26
Africa	38	11	33
Asia	112	32	108
Australia/Oceania	18	5	23
Total Consolidated Subsidiaries	1,503	633	1,427
Equity Companies			
United States	9	4	17
Europe	8	3	9
Asia	11	1	19
Total Equity Companies	28	8	45
Total gross and net wells drilling	1,531	641	1,472

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. ExxonMobi 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 fo on the Bakken oil play in North Dakota and Montana, the San Joaquin Basin of California, the Woodford and Caney Shales in the Ard Marietta and Arkoma basins of Oklahoma, the Permian Basin of West Texas and New Mexico, the Marcellus Shale of Pennsylvania and 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 develop wells were completed during the year. Development activities continued on the deepwater Hadrian South project and the non-operated L 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 acti 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 offshore. A total of 86.2 net exploration and development wells were completed during the year. Celtic Exploration Ltd. was acquired in 2

In Situ Bitumen Operations: ExxonMobil's year-end 2013 in situ bitumen acreage holdings totaled 0.7 million net onshore acres. A to 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 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 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 explo 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 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 exploratio 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 develop 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 durin year. On Block 15, project activities are under way at Kizomba Satellites Phase 2. On the non-operated Block 17, work continued c 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 d 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 comp
during the year. In 2013, ExxonMobil continued development drilling on the Satellite Field Development Phase 1 and the deepwater
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 durin
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
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
Qurna Phase I oil field during the year. Field rehabilitation activities continued during 2013, and across the life of this project will in
drilling of new wells, working over of existing wells, and optimization and debottlenecking of existing facilities. ExxonMobil sold a p
interest in West Qurna Phase I in 2013. In the Kurdistan Region of Iraq, ExxonMobil initiated a seismic program and exploration drilli
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 develop
wells were completed during 2013. Working with our partners, construction of the initial phase of the Kashagan field continued, and the p
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 to
5.0 net development wells were completed. Development activities continued on the Tapis and Damar projects and the Telok project start
in 2013.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil’s net acreage totaled 65 thousand acres offshore at year-end 2013. Durin
year, a total of 0.7 net development wells were completed. ExxonMobil participated in 61.8 million tonnes per year gross liquefied natur
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
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 acr
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 Z 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 acr onshore. During the year, a total of 6.7 net exploration and development wells were completed. The onshore oil concession expired in Ja 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 y 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 p consists of a subsea infrastructure for offshore production and transportation of the gas, and a 15.6 million tonnes per year LNG facility 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 Work continued on the Papua New Guinea (PNG) LNG project. The project consists of conditioning facilities in the southern PNG Highl 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 operation 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 d 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 specify the delivery of a fixed and determinable quantity for periods longer than one year. ExxonMobil also enters into natural gas contracts where the source of the natural gas used to fulfill the contract can be a combination of our own production and the spot m Worldwide, we are contractually committed to deliver approximately 2,800 billion cubic feet of natural gas for the period from 2014 th 2016. We expect to fulfill the majority of these delivery commitments with production from our proved developed reserves. Any rema 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	N
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	23,395	8,487	38,392	23,839	22,690	8,155	39,720	24
Canada/South America	5,486	4,990	4,478	1,762	5,283	4,825	4,271	1
Europe	1,254	352	649	269	1,255	346	622	
Africa	1,186	472	16	6	1,231	491	11	
Asia	756	270	207	151	792	370	204	
Australia/Oceania	661	147	38	19	676	152	40	
Total Consolidated Subsidiaries	32,738	14,718	43,780	26,046	31,927	14,339	44,868	26
Equity Companies								
United States	14,362	5,529	4,369	496	12,777	5,286	2,138	
Europe	49	17	555	173	71	27	585	
Asia	1,329	143	122	29	1,200	129	121	
Total Equity Companies	15,740	5,689	5,046	698	14,048	5,442	2,844	
Total gross and net productive wells	48,478	20,407	48,826	26,744	45,975	19,781	47,712	26

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 201
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	N
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	16,504	10,061	16,444	[illegible]
Canada/South America *(1)*	4,421	2,041	4,545	[illegible]
Europe	3,355	1,511	3,382	[illegible]
Africa	2,105	780	2,105	
Asia	1,828	557	1,322	
Australia/Oceania	2,123	758	2,018	
Total Consolidated Subsidiaries	30,336	15,708	29,816	[illegible]
Equity Companies				
United States	968	241	496	
Europe	4,341	1,356	4,344	[illegible]
Asia	5,731	640	5,731	
Total Equity Companies	11,040	2,237	10,571	[illegible]
Total gross and net developed acreage	41,376	17,945	40,387	[illegible]

(1) Includes developed acreage in South America of 214 gross and 109 net thousands of acres for 2013 and 618 gross and 202 net thou 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	N
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	7,645	4,722	8,517	[illegible]
Canada/South America *(1)*	16,319	9,232	16,669	[illegible]
Europe	13,461	6,585	35,928	[illegible]
Africa	20,877	13,446	12,005	[illegible]
Asia	18,639	13,979	24,346	[illegible]
Australia/Oceania	7,144	1,991	7,460	[illegible]
Total Consolidated Subsidiaries	84,085	49,955	104,925	[illegible]
Equity Companies				
United States	363	121	351	
Europe	-	-	-	
Asia	34,147	11,352	73	
Total Equity Companies	34,510	11,473	424	
Total gross and net undeveloped acreage	118,595	61,428	105,349	[illegible]

(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 4,4 thousands of acres for 2012.

ExxonMobil's investment in developed and undeveloped acreage is comprised of numerous concessions, blocks and leases. The term conditions under which the Corporation maintains exploration and/or production rights to the acreage are property-specific, contrac defined and vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any prope fully evaluated before expiration. In some instances, the Corporation may elect to relinquish acreage in advance of the contractual expi date if the evaluation process is complete and there is not a business basis for extension. In cases where additional time may be requi fully evaluate acreage, the Corporation has generally been successful in obtaining extensions. The scheduled expiration of lease 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 production ceases. Under certain circumstances, a lease may be held beyond its exploration term even if production has not commence 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 licen leases entitle the holder to continue existing licenses or leases upon completing specified work. In general, these license and lease agree are held as long as there is production on the licenses and leases. Exploration licenses in offshore eastern Canada and the Beaufort Sea are by work commitments of various amounts and rentals. They are valid for a maximum term of nine years. Production licenses in the off are valid for 25 years, with rights of extension for continued production. Significant discovery licenses in the offshore, relating to cur 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 se exploration period and up to two years for the third exploration period. A 50-percent relinquishment is required after each exploration p 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 exte possible, once a field has been developed. Argentine provinces are entitled to modify the concession terms granted within their territories concession terms of the exploration permits granted by Neuquen Province are up to six years for the initial exploration period, up to four for the second exploration period and up to three years for the third exploration period depending on the classification of the area. An exte 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 each. Extensions are subject to specific, minimum work commitments. Production licenses are normally granted for 20 to 25 years 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 period as explicitly defined in the license. The term is based on the period of time necessary to perform the activities for which the lice 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 Onshore production licenses issued prior to 1988 were indefinite; from 1988 they were issued for a period as explicitly defined in the lic ranging from 35 to 45 years. Offshore production licenses issued before 1976 were issued for a fixed period of 40 years; from 1976 they 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 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 bet 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 1 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 p 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 of up to 50 years, and with relinquishment of at least one-half of the original area required at the end of the initial period.

United Kingdom

Acreage terms are fixed by the government and are periodically changed. For example, many of the early licenses issued under the firs 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 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 ces of production; or licenses may continue in development areas for periods agreed on a case-by-case basis until they become producing are licenses terminate in all other areas. The licensing regime was last updated in 2002, and the majority of licenses issued have an initial te 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 ac 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 a optional second phase of two to three years. The production period is for 25 years, and agreements generally provide for a nego 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 cond of the permits, including relinquishment obligations, are specified in a negotiated convention. The production term is for 30 years and m 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, Industr Energy. The exploration periods are for 10 to 15 years with limited relinquishments in the absence of commercial discoveries. The produ period for crude oil is 30 years, while the production period for gas is 50 years. Under the Hydrocarbons Law enacted in 2006, the explo terms for new production sharing contracts are four to five years with a maximum of two one-year extensions, unless the Ministry a otherwise.

Nigeria

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

Some exploration activities are carried out in deepwater by joint ventures with local companies holding interests in an OPL. OP 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 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 f years onshore and 40 years in offshore areas and have been renewed, effective December 1, 2008, for a further period of 20 years, v further renewal option of 20 years. Operations under these pre-1969 OMLs are conducted under a joint venture agreement with NNPC than a PSC. In 2000, a Memorandum of Understanding (MOU) was executed defining commercial terms applicable to existing joint ventu 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 distincti onshore or offshore location and are renewable, upon 12 months’ written notice, for another period of 20 years. OMLs not held by NNP 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 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 explo period consists of three or four years with the possibility of a one to three-year extension. The production period, which includes develop 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 sh contract (PSC), negotiated with BPMIGAS, a government agency established in 2002 to manage upstream oil and gas activities. In Indonesia's Constitutional Court ruled certain articles of law relating to BPMIGAS to be unconstitutional, but stated that all existing signed with BPMIGAS should remain in force until their expiry, and the functions and duties previously performed by BPMIGAS are carried out by the relevant Ministry of the Government of Indonesia until the promulgation of a new oil and gas law. The current PSCs ha exploration period of six years, which can be extended up to 10 years, and an exploitation period of 20 years. PSCs generally requi contractor to relinquish 10 percent to 20 percent of the contract area after three years and generally allow the contractor to retain no more 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 Ministry of Oil. An ExxonMobil affiliate entered into a contract with South Oil Company of the Iraqi Ministry of Oil for the rig participate in the development and production activities of the West Qurna Phase I oil and gas field effective March 1, 2010. The term contract is 20 years with the right to extend for five years. The contract provides for cost recovery plus per-barrel fees for incre production above specified levels.

Exploration and production activities in the Kurdistan Region of Iraq are governed by production sharing contracts negotiated wi regional government of Kurdistan in 2011. The exploration term is for five years with the possibility of two-year extensions. The produ 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 agree 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 Kazak The exploration period is six years followed by separate appraisal periods for each discovery. The production period for each discovery, 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 recent PSCs governing exploration and production activities have an overall term of 24 to 38 years, depending on water depth, with po extensions to the exploration and/or development periods. The exploration period is five to seven years with the possibility of extensions which time areas with no commercial discoveries will be deemed relinquished. The development period is from four to six years commercial discovery, with the possibility of extensions under special circumstances. Areas from which commercial production has not s by the end of the development period will be deemed relinquished if no extension is granted. All extensions are subject to the nation company's prior written approval. The total production period is 15 to 25 years from first commercial lifting, not to exceed the overall te the contract.

In 2008, the Company reached agreement with the national oil company for a new PSC, which was subsequently signed in 2009. Und new PSC, from 2008 until March 31, 2012, the Company was entitled to undertake new development and production activities in oil under an existing PSC, subject to new minimum work and spending commitments, including an enhanced oil recovery project in one of t fields. When the existing PSC expired on March 31, 2012, the producing fields covered by the existing PSC automatically became part 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 perm 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 ma June 1995.

Russia

Terms for ExxonMobil's Sakhalin acreage are fixed by the production sharing agreement (PSA) that became effective in 1996 betwee Russian government and the Sakhalin-1 consortium, of which ExxonMobil is the operator. The term of the PSA is 20 years fror 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 that cover certain of Rosneft's offshore licenses. The Kara Sea licenses extend through 2040 and include an exploration period through development plan submission within eight years of a discovery and development activities within five years of plan approval. The Blac 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 gen 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 conce agreement executed in 1939, which expired in January 2014. An interest in the development and production activities of the Upper Z field, a major offshore field, was acquired effective as of January 2006, for a term expiring March 2026, and in 2013 the governing agree were extended to 2041.

AUSTRALIA/OCEANIA

Australia

Exploration and production activities conducted offshore in Commonwealth waters are governed by Federal legislation. Exploration pe are granted for an initial term of six years with two possible five-year renewal periods. Retention leases may be granted for resources th not commercially viable at the time of application, but are expected to become commercially viable within 15 years. These are grant periods of five years and renewals may be requested. Prior to July 1998, production licenses were granted initially for 21 years, with a fu renewal of 21 years and thereafter "indefinitely", i.e., for the life of the field. Effective from July 1998, new production licenses are gr "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 years with a five-year extension possible (an additional extension of three years is possible in certain circumstances). Generally, a 50-pe relinquishment of the license area is required at the end of the initial six-year term, if extended. Petroleum Development licenses are gr for an initial 25-year period. An extension of up to 20 years may be granted at the Minister's discretion. Petroleum Retention licenses m granted for gas resources that are not commercially viable at the time of application, but may become commercially viable withi maximum possible retention time of 15 years. Petroleum Retention licenses are granted for five-year terms, and may be extended, a Minister's discretion, twice for the maximum retention time of 15 years. Extensions of Petroleum Retention licenses may be for periods c than one year, renewable annually, if the Minister considers at the time of extension that the resources could become commercially via 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 g network of manufacturing plants, transportation systems, and distribution centers that provide a range of fuels, lubricants and other pro and feedstocks to our customers around the world.

Refining Capacity At Year-End 2013 *(1)*

		ExxonMobil Share KBD *(2)*	ExxonMob Interest %
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, le 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 operatic ExxonMobil and majority-owned subsidiaries. For companies owned 50 percent or less, ExxonMobil share is the greater of ExxonM 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, wide variety of other petrochemicals.

Chemical Complex Capacity At Year-End 2013 *(1)(2)*

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMo 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 o capacity is ExxonMobil's interest.

ITEM 3. LEGAL PROCEEDINGS

In November 2013, the Texas Commission on Environmental Quality (TCEQ) contacted Exxon Mobil Corporation (the "Corpora concerning alleged violations of the Texas Clean Air Act, implementing regulations and the applicable new source review permit in conne with exceedances of volatile organic compound emissions from Tank 22 at the Corporation's King Ranch Gas Plant. TCEQ is seeking a 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 Energy Inc. (XTO) resolving the air enforcement matter previously reported in the Corporation's Forms 10-Q for the first and second qu of 2013, pursuant to the terms of the Administrative Consent Agreement, during the fourth quarter of 2013, XTO provided the NDDOH an updated list of well sites on newly acquired assets with air emission control issues. On November 12, 2013, XTO paid an additional pe 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 Wel in Penn Township, Pennsylvania, reported most recently in the Corporation's Form 10-Q for the third quarter of 2013, on January 2, 20 Pennsylvania state magistrate ruled that the Attorney General's Office had presented sufficient evidence for the charges to proceed to tr the Pennsylvania Court of Common Pleas. At the trial, XTO will have an opportunity to present its full defense to the charges, wh believes are unwarranted.

Regarding the settlement of matters between the Louisiana Department of Environmental Quality (LDEQ) and ExxonMobil Refinin Supply Company and ExxonMobil Chemical Company, both divisions of the Corporation, involving ExxonMobil facilities in Baton R Louisiana, last reported in the Corporation's Form 10-Q for the third quarter of 2013, during the fourth quarter of 2013, the public com period on the proposed settlement ended, and the Louisiana Attorney General issued his concurrence with regard to the settlement terms parties executed the final documents in January 2014, thereby resolving the matters covered by the settlement. The settlement terms in payment of a $300,000 penalty, an agreement to complete certain on-site improvement projects valued at $1,000,000, Bene 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, incl a penalty of $126,250, concerning emission events at ExxonMobil Oil Corporation's (EMOC) Beaumont Refinery previously reported 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 soi groundwater at a former Mobil petroleum terminal at Lighthouse Point in Ogdensburg, New York, previously reported in the Corpora Form 10-Q for the third quarter of 2011, the parties reached a settlement agreement that was entered into the court record on Novemb 2013. On December 16, 2013, the parties signed the agreement, and EMOC made a payment to the State of $8.05 million, pursuant agreement's terms.

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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 l 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 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 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 Corpo October 1, 2006 – March 31, 2009. He became Senior Vice President of Exxon Mobil Corporation on April 1, 2009, a position he still 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 Pres 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

Mr. Randy J. Cleveland was Production Manager, U.S. Production, ExxonMobil Production Company April 1, 2006 – April 30, 2009 was Planning & Commercial Manager, ExxonMobil Production Company May 1, 2009 – June 24, 2010. He was Vice President, Integration, XTO Energy Inc. June 25, 2010 – January 31, 2012. He was Executive Vice President, XTO Energy Inc. February 1, 2 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 President – Corporate Strategic Planning of Exxon Mobil Corporation on February 1, 2009, a position he still holds as of this filing dat

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 Pres Asia Pacific/Middle East, ExxonMobil Exploration Company June 1, 2009 – March 31, 2012. He was Executive Assistant t Chairman, Exxon Mobil Corporation April 1, 2012 – February 28, 2013. He became President of ExxonMobil Upstream Ventures anc 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 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, 200 was Vice President of Exxon Mobil Corporation and President, ExxonMobil Upstream Ventures May 1, 2009 – February 28, 2013 became President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation on March 1, 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 Preside ExxonMobil Upstream Research Company June 1, 2009 – August 31, 2010. He became President of ExxonMobil Exploration Con 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 I Corporation on December 1, 2007. On February 1, 2012, the businesses of ExxonMobil Lubricants & Petroleum Specialties Compan ExxonMobil Fuels Marketing Company were consolidated and Mr. Kelly became President of the combined ExxonMobil Fuels, Lubr & 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) July 1, 2004 (Controller)	Age: 62

Mr. Patrick T. Mulva became Vice President of Exxon Mobil Corporation on February 1, 2002 and Controller of Exxon Mobil Corpo: 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 Che 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, 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 Ass Treasurer of Exxon Mobil Corporation February 1, 2009 – April 30, 2011. He became Vice President and Treasurer of Exxon I 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 be 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 President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation April 1, 2009 – Februa 2013. He became President of ExxonMobil Production Company and Vice President of Exxon Mobil Corporation on March 1, 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, 2 June 30, 2010. He was Vice President, Supply & Transportation, ExxonMobil Refining & Supply Company July 1, 2010 – July 31, 2 He became President of ExxonMobil Refining & Supply Company and Vice President of Exxon Mobil Corporation on August 1, 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 o 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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Num of Shares that M Yet Be Purchas Under the Plans 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 b offset shares issued in conjunction with company benefit plans and programs and to gradually reduce the number of shares outstanding announcement did not specify an amount or expiration date. The Corporation has continued to purchase shares since this announcement a report purchased volumes in its quarterly earnings releases. In its most recent earnings release dated January 30, 2014, the Corporation s that first quarter 2014 share purchases are continuing at a pace consistent with fourth quarter 2013 share reduction spending of $3 bi Purchases may be made in both the open market and through negotiated transactions, and purchases may be increased, decreas discontinued at any time without prior notice.

ITEM 6. SELECTED FINANCIAL DATA

	Years Ended December 31,				
	2013	2012	2011	2010	200
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	420,836	451,509	467,029	370,125	301
(1) Sales-based taxes included	*30,589*	*32,409*	*33,503*	*28,547*	*25*
Net income attributable to ExxonMobil	32,580	44,880	41,060	30,460	19
Earnings per common share	7.37	9.70	8.43	6.24	
Earnings per common share - assuming dilution	7.37	9.70	8.42	6.22	
Cash dividends per common share	2.46	2.18	1.85	1.74	
Total assets	346,808	333,795	331,052	302,510	233
Long-term debt	6,891	7,928	9,322	12,227	7

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" i 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 Uncertainties," in the Financial Section of this report. All statements other than historical information incorporated in this Item 7A are for looking statements. The actual impact of future market changes could differ materially due to, among other things, factors discussed i 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, beginning with the section entitled “Report of Independent Registered Public Accounting Firm” and continuing through “No 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 consoli financial statements or notes thereto.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIA 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 Office Principal Accounting Officer have evaluated the Corporation’s disclosure controls and procedures as of December 31, 2013. Based o evaluation, these officers have concluded that the Corporation’s disclosure controls and procedures are effective in ensuring that inform required to be disclosed by the Corporation in the reports that it files or submits under the Securities Exchange Act of 1934, as amend accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effecti ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the Securitie 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 respo for establishing and maintaining adequate internal control over the Corporation’s financial reporting. Management conducted an evaluati the effectiveness of internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management conclude 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 in 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 affec 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 shareholder "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 Execu Officer Stock Ownership";
- The portions entitled "Director Qualifications" and "Code of Ethics and Business Conduct" of the section entitled "Corpo Governance"; and
- The "Audit Committee" portion and the membership table of the portion entitled "Board Meetings and Committees; An 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 Discu and Analysis" and "Executive Compensation Tables" of the registrant's 2014 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELAT STOCKHOLDER MATTERS

The information required under Item 403 of Regulation S-K is incorporated by reference to the sections "Director and Executive Officer Ownership" and "Certain Beneficial Owners" of the registrant's 2014 Proxy Statement.

Equity Compensation Plan Information

Plan Category	*(a)* Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	*(b)* Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	*(c)* Number of Securitie Remaining Availabl for Future Issuanc Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	17,358,275 *(1)(2)*	-	117,260,597 *(2)(3*
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 secu to be issued upon exercise of outstanding options under XTO Energy Inc. plans was 1,505,820, and the weighted-average exercise pr 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 s available for award under the 2003 Incentive Program and 641,200 shares available for award under the 2004 Non-Employee Di Restricted Stock Plan.

(4) Under the 2004 Non-Employee Director Restricted Stock Plan approved by shareholders in May 2004, and the related standing reso adopted by the Board, each non-employee director automatically receives 8,000 shares of restricted stock when first elected to the and, if the director remains in office, an additional 2,500 restricted shares each following year. While on the Board, each non-emp director receives the same cash dividends on restricted shares as a holder of regular common stock, but the director is not allowed t 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 se 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 en “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

TABLE OF CONTENTS

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

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

Operating	2013	2012		2013	20
	(thousands of barrels daily)			*(thousands of barrels*	
Net liquids production			Refinery throughput		
United States	431	418	United States	1,819	1
Non-U.S.	1,771	1,767	Non-U.S.	2,766	3
Total	2,202	2,185	Total	4,585	5
	(millions of cubic feet daily)			*(thousands of barrels*	
Natural gas production available for sale			Petroleum product sales		
United States	3,545	3,822	United States	2,609	2
Non-U.S.	8,291	8,500	Non-U.S.	3,278	3
Total	11,836	12,322	Total	5,887	6
	(thousands of oil-equivalent barrels daily)			*(thousands of metri*	
Oil-equivalent production *(1)*	4,175	4,239	Chemical prime product sales *(2)*		
			United States	9,679	9
			Non-U.S.	14,384	14
			Total	24,063	24

(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	20
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	420,836	451,509	467,029	370,125	301
Earnings					
Upstream	26,841	29,895	34,439	24,097	17
Downstream	3,449	13,190	4,459	3,567	1
Chemical	3,828	3,898	4,383	4,913	2
Corporate and financing	(1,538)	(2,103)	(2,221)	(2,117)	(1
Net income attributable to ExxonMobil	32,580	44,880	41,060	30,460	19
Earnings per common share	7.37	9.70	8.43	6.24	
Earnings per common share – assuming dilution	7.37	9.70	8.42	6.22	
Cash dividends per common share	2.46	2.18	1.85	1.74	
Earnings to average ExxonMobil share of equity (percent)	19.2	28.0	27.3	23.7	
Working capital	(12,416)	321	(4,542)	(3,649)	3
Ratio of current assets to current liabilities (times)	0.83	1.01	0.94	0.94	
Additions to property, plant and equipment	37,741	35,179	33,638	74,156	22
Property, plant and equipment, less allowances	243,650	226,949	214,664	199,548	139
Total assets	346,808	333,795	331,052	302,510	233
Exploration expenses, including dry holes	1,976	1,840	2,081	2,144	2
Research and development costs	1,044	1,042	1,044	1,012	1
Long-term debt	6,891	7,928	9,322	12,227	7
Total debt	22,699	11,581	17,033	15,014	9
Fixed-charge coverage ratio (times)	55.7	62.4	53.4	42.2	
Debt to capital (percent)	11.2	6.3	9.6	9.0	
Net debt to capital (percent) *(2)*	9.1	1.2	2.6	4.5	
ExxonMobil share of equity at year-end	174,003	165,863	154,396	146,839	110
ExxonMobil share of equity per common share	40.14	36.84	32.61	29.48	2
Weighted average number of common shares outstanding (millions)	4,419	4,628	4,870	4,885	4
Number of regular employees at year-end (thousands) *(3)*	75.0	76.9	82.1	83.6	
CORS employees not included above (thousands) *(4)*	9.8	11.1	17.0	20.1	

(1) Sales and other operating revenue includes sales-based taxes of $30,589 million for 2013, $32,409 million for 2012, $33,503 millio 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 o 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 provic
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 sa
subsidiaries, property, plant and equipment, and sales and returns of investments from the Consolidated Statement of Cash Flows. This
flow reflects the total sources of cash from both operating the Corporation's assets and from the divesting of assets. The Corporation empl
long-standing and regular disciplined review process to ensure that all assets are contributing to the Corporation's strategic objectives. A
are divested when they are no longer meeting these objectives or are worth considerably more to others. Because of the regular nature c
activity, we believe it is useful for investors to consider proceeds associated with asset sales together with cash provided by operating acti
when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

Cash flow from operations and asset sales	**2013**	**2012**	**2(**
		(millions of dollars)	
Net cash provided by operating activities	44,914	56,170	55
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	2,707	7,655	11
Cash flow from operations and asset sales	47,621	63,825	66

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 inc
ExxonMobil's net share of property, plant and equipment and other assets less liabilities, excluding both short-term and long-term debt. '
viewed from the perspective of the sources of capital employed in total for the Corporation, it includes ExxonMobil's share of total del
equity. Both of these views include ExxonMobil's share of amounts applicable to equity companies, which the Corporation believes shou
included to provide a more comprehensive measure of capital employed.

Capital employed	**2013**	**2012**	**2(**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	346,808	333,795	331
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(55,916)	(60,486)	(69
Total long-term liabilities excluding long-term debt	(87,698)	(90,068)	(83
Noncontrolling interests share of assets and liabilities	(8,935)	(6,235)	(7
Add ExxonMobil share of debt-financed equity company net assets	6,109	5,775	4
Total capital employed	200,368	182,781	175
Total corporate sources: debt and equity perspective			
Notes and loans payable	15,808	3,653	7
Long-term debt	6,891	7,928	9
ExxonMobil share of equity	174,003	165,863	154
Less noncontrolling interests share of total debt	(2,443)	(438)	
Add ExxonMobil share of equity company debt	6,109	5,775	4
Total capital employed	200,368	182,781	175

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

Return on average capital employed	**2013**	**2012**	**2(**
		(millions of dollars)	
Net income attributable to ExxonMobil	32,580	44,880	41
Financing costs (after tax)			
Gross third-party debt	(163)	(401)	
ExxonMobil share of equity companies	(239)	(257)	
All other financing costs – net	83	100	
Total financing costs	(319)	(558)	
Earnings excluding financing costs	32,899	45,438	41
Average capital employed	191,575	179,094	17(
Return on average capital employed – corporate total	17.2%	25.4%	2

QUARTERLY INFORMATION

	2013					2012				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Ye
Volumes										
Production of crude oil					*(thousands of barrels daily)*					
and natural gas liquids, synthetic oil and bitumen	2,193	2,182	2,199	2,235	2,202	2,214	2,208	2,116	2,203	
Refinery throughput	4,576	4,466	4,847	4,452	4,585	5,330	4,962	4,929	4,837	
Petroleum product sales	5,755	5,765	6,031	5,994	5,887	6,316	6,171	6,105	6,108	
Natural gas production					*(millions of cubic feet daily)*					
available for sale	13,213	11,354	10,914	11,887	11,836	14,036	11,661	11,061	12,541	1
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production *(1)*	4,395	4,074	4,018	4,216	4,175	4,553	4,152	3,960	4,293	
					(thousands of metric tons)					
Chemical prime product sales	5,910	5,831	6,245	6,077	24,063	6,337	5,972	5,947	5,901	2
Summarized financial data										
Sales and other operating					*(millions of dollars)*					
revenue *(2)(3)*	103,378	103,050	108,390	106,018	420,836	118,961	112,398	110,989	109,161	45
Gross profit *(4)*	30,083	28,689	30,300	29,901	118,973	35,672	32,715	33,209	31,969	13
Net income attributable to ExxonMobil	9,500	6,860	7,870	8,350	32,580	9,450	15,910	9,570	9,950	4
Per share data					*(dollars per share)*					
Earnings per common share *(5)*	2.12	1.55	1.79	1.91	7.37	2.00	3.41	2.09	2.20	
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	
Dividends per common share	0.57	0.63	0.63	0.63	2.46	0.47	0.57	0.57	0.57	
Common stock prices										
High	91.93	93.50	95.49	101.74	101.74	87.94	87.67	92.57	93.67	
Low	86.59	85.02	85.61	84.79	84.79	83.19	77.13	82.83	84.70	

(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 Exxonl common stock is traded. The principal market where ExxonMobil common stock (XOM) is traded is the New York Stock Exchange, altl 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 regis 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.

FUNCTIONAL EARNINGS

	2013	2012	20
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	4,191	3,925	5
Non-U.S.	22,650	25,970	29
Downstream			
United States	2,199	3,575	2
Non-U.S.	1,250	9,615	2
Chemical			
United States	2,755	2,220	2
Non-U.S.	1,073	1,678	2
Corporate and financing	(1,538)	(2,103)	(2
Net income attributable to ExxonMobil (U.S. GAAP)	32,580	44,880	41
Earnings per common share	7.37	9.70	
Earnings per common share – assuming dilution	7.37	9.70	

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

FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual f results, including demand growth and energy source mix; capacity increases; production growth and mix; rates of field decline; fina sources; the resolution of contingencies and uncertain tax positions; environmental and capital expenditures; could differ materially depe on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical product 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 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 no consolidated financial statements to which they refer, are the responsibility of the management of Exxon Mobil Corporation. The Corpora accounting and financial reporting fairly reflect its straightforward business model involving the extracting, manufacturing and marketi hydrocarbons and hydrocarbon-based products. The Corporation's business model involves the production (or purchase), manufacture an 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-position participate in substantial investments to develop new energy supplies. While commodity prices are volatile on a short-term basis and depe supply and demand, ExxonMobil's investment decisions are based on our long-term business outlook, using a disciplined approach in sele and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the bas setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for inves evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Price ranges for cruc natural gas, refined products, and chemical products are based on corporate plan assumptions developed annually by major region an utilized for investment evaluation purposes. Potential investment opportunities are tested over a wide range of economic scenarios to est the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learne 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. Coinc with this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. As economie populations grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with signi efficiency gains, global energy demand is projected to rise by about 35 percent from 2010 to 2040. This demand increase is expected concentrated in developing countries (i.e., those that are not member nations of the Organisation for Economic Co-operation Development).

As expanding prosperity drives global energy demand higher, increasing use of energy-efficient and lower-emission fuels, technologie practices will continue to help significantly reduce energy consumption and emissions per unit of economic output over time. Subst efficiency gains are likely in all key aspects of the world's economy through 2040, affecting energy requirements for transportation, p 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 20 2040. The global growth in transportation demand is likely to account for approximately 70 percent of the growth in liquid fuels demand this period. Nearly all the world's transportation fleets will continue to run on liquid fuels because they are abundant, widely available, ea 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 coun Consistent with this projection, power generation is expected to remain the largest and fastest-growing major segment of global e demand. Meeting the expected growth in power demand will require a diverse set of energy sources. Natural gas demand is likely to grow significantly and become the leading source of generated electricity by 2040, reflecting the efficiency of gas-fired power plants. Today 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 r environmental impacts including those related to local air quality and greenhouse gas emissions. Nuclear power and renewables, l hydropower and wind, are also expected to grow significantly over the period.

Liquid fuels provide the largest share of global energy supplies today due to their broad-based availability, affordability and ea transportation, distribution and storage to meet consumer needs. By 2040, global demand for liquid fuels is expected to grow to approxin 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 so Globally, conventional crude production will likely decline slightly through 2040. However, this decline is expected to be more than off rising production from a wide variety of emerging supply sources – including tight oil, deepwater, oil sands, natural gas liquids and bio The world's resource base is sufficient to meet projected demand through 2040 as technology advances continue to expand the availabil economic supply options. However, access to resources and timely investments will remain critical to meeting global needs with rel 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 th 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 v Helping meet these needs will be significant growth in supplies of unconventional gas – the natural gas found in shale and other formations that was once considered uneconomic to produce. About 65 percent of the growth in natural gas supplies is expected to be unconventional sources, which will account for about one-third of global gas supplies by 2040. Growing natural gas demand wil stimulate significant growth in the worldwide liquefied natural gas (LNG) market, which is expected to reach about 15 percent of glob 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 w 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 n 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 20 percent. Nuclear power is projected to grow significantly, albeit at a slower pace than otherwise expected in the aftermath of the Fuku incident in Japan following the earthquake and tsunami in March 2011. Total renewable energy is likely to reach close to 15 percent o energy by 2040, with biomass, hydro and geothermal contributing a combined share of about 11 percent. Total energy supplied from solar and biofuels is expected to increase close to 450 percent from 2010 to 2040, reaching a combined share of about 4 percent of energy.

The Corporation anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also reserve increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these reso will be significant. According to the International Energy Agency, the investment required to meet total oil and gas energy needs worl 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 unc timing and outcome, making it difficult to predict their business impact. ExxonMobil includes estimates of potential costs related to po public policies covering energy-related greenhouse gas emissions in its long-term Outlook for Energy, which is used for assessing the bu environment and in its investment evaluations.

The information provided in the Long-Term Business Outlook includes ExxonMobil's internal estimates and forecasts based upon in 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 selective, maximizing shareholder value and mitigating political and technical risks. ExxonMobil's fundamental Upstream business stra guide our global exploration, development, production, and gas and power marketing activities. These strategies include identifyin selectively capturing the highest quality opportunities, exercising a disciplined approach to investing and cost management, developin applying high-impact technologies, maximizing the profitability of existing oil and gas production, and capitalizing on growing natural ga power markets. These strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technol 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 n its production volumes between now and 2018. Oil equivalent production from North America is expected to increase over the next five based on current capital activity plans. Currently, this growth area accounts for 32 percent of the Corporation's production. By 2018 expected to generate about 35 percent of total volumes. The remainder of the Corporation's production is expected to include contrib 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 vol are produced. Production from diverse resource types utilizing specialized technologies such as arctic technology, deepwater drillin production systems, heavy oil and oil sands recovery processes, unconventional gas and oil production and

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 antic that the expected change in the geographic mix of production volumes, and in the types of opportunities from which volumes will be prod 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 i level of unit operating expenses. The Corporation's overall volume capacity outlook, based on projects coming onstream as anticipated, production capacity to grow over the period 2014-2018. However, actual volumes will vary from year to year due to the timing of indiv project start-ups and other capital activities, operational outages, reservoir performance, performance of enhanced oil recovery pro regulatory changes, asset sales, weather events, price effects under production sharing contracts and other factors described in Item 1A. Factors. Enhanced oil recovery projects extract hydrocarbons from reservoirs in excess of that which may be produced through pr recovery, i.e., through pressure depletion or natural aquifer support. They include the injection of water, gases or chemicals into a reserv produce hydrocarbons otherwise unobtainable.

Downstream

ExxonMobil's Downstream is a large, diversified business with refining, logistics, and marketing complexes around the world. Corporation has a presence in mature markets in North America and Europe, as well as in the growing Asia Pacific region. ExxonM fundamental Downstream business strategies position the company to deliver long-term growth in shareholder value that is superi competition across a range of market conditions. These strategies include maintaining best-in-class operations in all aspects of the bus maximizing value from leading-edge technologies, capitalizing on integration across ExxonMobil businesses, selectively investing for res 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 da lubricant basestock manufacturing capacity of 126 thousand barrels per day. ExxonMobil's fuels and lubes marketing businesses significant global reach, with multiple channels to market serving a diverse customer base. Our portfolio of world-renowned brands inc *Exxon*, *Mobil*, *Esso* and *Mobil 1*.

The downstream industry environment remains challenging. Demand weakness and overcapacity in the refining sector will continue t pressure on margins. In the near term, we see variability in refining margins, with some regions seeing stronger margins as refi rationalize. In North America, lower raw material and energy cost driven by increasing crude oil and natural gas production has strengtl 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 for its raw materials (primarily crude oil) and the market prices for the range of products produced (primarily gasoline, heating oil, diese jet fuel and fuel oil). Crude oil and many products are widely traded with published prices, including those quoted on multiple exch around the world (e.g., New York Mercantile Exchange and Intercontinental Exchange). Prices for these commodities are determined b global marketplace and are influenced by many factors, including global and regional supply/demand balances, inventory levels, inc 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 new capacity additions outpace the growth in global demand. Additionally, as described in more detail in Item 1A. Risk Factors, pro carbon policy and other climate-related regulations in many countries, as well as the continued growth in biofuels mandates, could negative impacts on the refining business. ExxonMobil's integration across the value chain, from refining to marketing, enhances overall in both fuels and lubricants businesses.

In the retail fuels marketing business, competition has caused inflation-adjusted margins to decline. In 2013, ExxonMobil complete previously announced transition of the direct served (i.e., dealer, company-operated) retail network in the U.S. to a more capital-eff branded distributor model and progressed this same model in portions of Europe. ExxonMobil is increasing investment in its fuels brand developing multiple programs that will enhance the value of its consumer retail offer. The company's lubricants business continues to leveraging world-class brands and integration with industry-leading basestock refining capability. ExxonMobil remains the market lea 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 over the past decade. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. These investi capitalize on the Corporation's world-class scale and integration, industry leading efficiency, leading-edge technology and respected bi enabling ExxonMobil to take advantage of attractive emerging growth opportunities around the globe. In 2013, the company comple hydrotreater project at the Singapore refinery to produce ultra-low sulfur diesel, and a cogeneration project at the Augusta, Italy refin improve energy efficiency. Additionally, construction of a lower sulfur fuels facility at the joint Saudi Aramco and ExxonMobil SAM Refinery in Yanbu, Saudi Arabia is nearly complete. The company is also expanding lubricant basestock manufacturing capacity at refi in Baytown, Texas and Singapore, and expanding lube oil blending plants in China, Finland, and the U.S. to support future demand growth for fir lubricants in key markets.

Chemical

Worldwide petrochemical demand grew in 2013, led by growing demand from Asia manufacturers and consumers. North America cont to benefit from abundant supplies of natural gas and gas liquids, providing both low-cost feedstock and energy savings. Specialty pr 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 bal 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 sit significantly increasing premium and specialty products capacity. Singapore is now ExxonMobil's largest integrated petrochemical comp

REVIEW OF 2013 AND 2012 RESULTS

	2013	2012	2(
		(millions of dollars)	
Earnings (U.S. GAAP)	32,580	44,880	41

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

	2013	2012	2(
		(millions of dollars)	
Upstream			
United States	4,191	3,925	5
Non-U.S.	22,650	25,970	29
Total	26,841	29,895	34

2013

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

2012

Upstream earnings were $29,895 million, down $4,544 million from 2011. Lower liquids realizations, partly offset by improved natur realizations, decreased earnings by about $100 million. Production volume and mix effects decreased earnings by $2.3 billion. All other i including higher operating expenses, unfavorable tax items, lower gains on asset sales, and unfavorable foreign exchange effects, re earnings by $2.1 billion. On an oil-equivalent basis, production was down 5.9 percent compared to 2011. Excluding the impac entitlement volumes, OPEC quota effects and divestments, production was down 1.7 percent. Liquids production of 2,185 kbd decr 127 kbd from 2011. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production was down 1.6 percent, as field decline was partly offset by project ran in West Africa and lower downtime. Natural gas production of 12,322 mcfd decreased 840 mcfd from 2011. Excluding the impa entitlement volumes and divestments, natural gas production was down 1.9 percent, as field decline was partially offset by higher deman lower downtime. Earnings from U.S. Upstream operations for 2012 were $3,925 million, down $1,171 million from 2011. Earnings ou the U.S. were $25,970 million, down $3,373 million.

Upstream additional information

	2013	2012	20
		(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production)*(1)*			
Prior year	4,239	4,506	4,
Entitlements - Net Interest	(38)	(129)	
Entitlements - Price / Spend	(9)	(10)	(
Quotas	3	9	
Divestments	(26)	(61)	
Net growth	6	(76)	
Current Year	4,175	4,239	4,

(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 terms.

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

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

Downstream

	2013	2012	20
		(millions of dollars)	
Downstream			
United States	2,199	3,575	2
Non-U.S.	1,250	9,615	2
Total	3,449	13,190	4

2013

Downstream earnings of $3,449 million decreased $9,741 million from 2012 driven by the absence of the $5.3 billion gain associated wi Japan restructuring. Lower margins, mainly refining, decreased earnings by $2.9 billion. Volume and mix effects decreased earnin $310 million. All other items, including higher operating expenses, unfavorable foreign exchange impacts, and lower divestments, decr earnings by $1.2 billion. Petroleum product sales of 5,887 kbd decreased 287 kbd from 2012. U.S. Downstream earnings were $2,199 mi 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 earnin $2.6 billion, while volume and mix effects increased earnings by about $200 million. All other items increased earnings by $5.9 billio primarily to the $5.3 billion gain associated with the Japan restructuring and other divestment gains. Petroleum product sales of 6,17 decreased 239 kbd from 2011 due mainly to the Japan restructuring and divestments. U.S. Downstream earnings were $3,575 millic $1,307 million from 2011. Non-U.S. Downstream earnings were $9,615 million, an increase of $7,424 million from 2011.

Chemical

	2013	2012	20
		(millions of dollars)	
Chemical			
United States	2,755	2,220	2
Non-U.S.	1,073	1,678	2
Total	3,828	3,898	4

2013

Chemical earnings of $3,828 million were $70 million lower than 2012. The absence of the gain associated with the Japan restruct decreased earnings by $630 million. Higher margins increased earnings by $480 million, while volume and mix effects increased earnin $80 million. Prime product sales of 24,063 kt (thousands of metric tons) were down 94 kt from 2012. U.S. Chemical earnings $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 e lowered earnings by $100 million. All other items increased earnings by $50 million, as a $630 million gain associated with the restructuring and favorable tax impacts were mostly offset by unfavorable foreign exchange effects and higher operating expenses. 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 Chemical earnings were $1,678 million, $490 million lower than 2011.

Corporate and Financing

	2013	2012	20
		(millions of dollars)	
Corporate and financing	(1,538)	(2,103)	(2

2013

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

2012

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2013	2012	20
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	44,914	56,170	55
Investing activities	(34,201)	(25,601)	(22
Financing activities	(15,476)	(33,868)	(28
Effect of exchange rate changes	(175)	217	
Increase/(decrease) in cash and cash equivalents	(4,938)	(3,082)	4
		(December 31)	
Cash and cash equivalents	4,644	9,582	12
Cash and cash equivalents - restricted	269	341	
Total cash and cash equivalents	4,913	9,923	13

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 were net income including noncontrolling interests of $33.4 billion, the adjustment for the noncash provision of $17.2 billion for deprec and depletion, and a net debt increase of $11.6 billion. The major uses of funds included spending for additions to property, plan equipment of $33.7 billion, the purchase of shares of ExxonMobil stock of $16.0 billion, dividends to shareholders of $10.9 billion change in working capital, excluding cash and debt, of $4.7 billion. Included in total cash and cash equivalents at year-end 2013 was 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 h adjustment for noncash transactions were more than offset by lower proceeds from sales of subsidiaries and property, plant and equipm 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 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 the majority of financial requirements, and may be supplemented by long-term and short-term debt, including a revolving commercial program. The Corporation has committed lines of credit of $6.5 billion which were unused as of December 31, 2013. Cash that m temporarily available as surplus to the Corporation's immediate needs is carefully managed through counterparty quality and inves 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 develo apply new technologies and recovery processes to existing fields, in order to maintain or increase production. After a period of product plateau rates, it is the nature of oil and gas fields eventually to produce at declining rates for the remainder of their economic life. Ave over all the Corporation's existing oil and gas fields and without new projects, ExxonMobil's production is expected to decline at an avera approximately 3 percent per year over the next few years. Decline rates can vary widely by individual field due to a number of fa including, but not limited to, the type of reservoir, fluid properties, recovery mechanisms, work activity, and age of the field. Furthermor 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 q opportunities and project execution. Over the last decade, this has resulted in net annual additions to proved reserves that have exceede amount produced. Projects are in progress or planned to increase production capacity. However, these volume increases are subject to a v of risks including project start-up timing, operational outages, reservoir performance, crude oil and natural gas prices, weather events regulatory changes. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please refer to Item 1A. 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 were $42.5 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an average inves profile of about $37 billion per year for the next several years. Actual spending could vary depending on the progress of individual project property acquisitions. The Corporation has a large and diverse portfolio of development projects and exploration opportunities, which mitigate the overall political and technical risks of the Corporation's Upstream segment and associated cash flow. Further, due to its fin strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not h significant impact on the

Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments. The purchase and sale of o 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 in including noncontrolling interests of $33.4 billion, a decrease of $14.2 billion. The noncash provision of $17.2 billion for depreciatio depletion was higher than 2012. The adjustment for net gains on asset sales was $1.8 billion compared to an adjustment of $13.0 billi 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 in including noncontrolling interests of $47.7 billion, an increase of $5.5 billion. The noncash provision of $15.9 billion for depreciatio depletion was slightly higher than 2011. The adjustments for other noncash transactions and changes in operational working capital, excl 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 equipm $33.7 billion decreased $0.6 billion from 2012. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sale returns of investments of $2.7 billion compared to $7.7 billion in 2012. Additional investments and advances were $3.8 billion higher in 2

2012

Cash used in investment activities netted to $25.6 billion in 2012, $3.4 billion higher than 2011. Spending for property, plant and equipm $34.3 billion increased $3.3 billion from 2011. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sale 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 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 increas $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 billi $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 by reductions for distributions to ExxonMobil shareholders of $10.9 billion of dividends and $15.0 billion of purchases of shar 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 bi These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plan programs. Shares outstanding were reduced by 3.7 percent from 4,502 million to 4,335 million at the end of 2013. Purchases were ma both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without notice.

2012

Cash used in financing activities was $33.9 billion in 2012, $5.6 billion higher than 2011. Dividend payments on common shares increas $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 billion at year-end.

ExxonMobil share of equity increased $11.5 billion to $165.9 billion. The addition to equity for earnings of $44.9 billion was partially by reductions for distributions to ExxonMobil shareholders of $10.1 billion of dividends and $20.0 billion of purchases of shar 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 bi These purchases were to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plan programs. Shares outstanding were reduced by 4.9 percent from 4,734 million to 4,502 million at the end of 2012. Purchases were ma both the open market and through negotiated transactions.

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 20 combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

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

This table excludes commodity purchase obligations (volumetric commitments but no fixed or minimum price) which are resold shortly purchase, either in an active, highly liquid market or under long-term, unconditional sales contracts with similar pricing terms. Exa include long-term, noncancelable LNG and natural gas purchase commitments and commitments to purchase refinery products at m prices. Inclusion of such commitments would not be meaningful in assessing liquidity and cash flow, because these purchases will be off the same periods by cash received from the related sales transactions. The table also excludes unrecognized tax benefits totaling $7.8 billi of December 31, 2013, because the Corporation is unable to make reasonably reliable estimates of the timing of cash settlements wi respective taxing authorities. Further details on the unrecognized tax benefits can be found in Note 19, Income, Sales-Based and Other Ta

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 postretirement plans at year end. The payments by period include expected contributions to funded pension plans in 2014 and esti benefit payments for unfunded plans in all years.

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

(6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable or cancelable only under c conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services undiscounted obligations of $1,236 million mainly pertain to pipeline throughput agreements and include $457 million of obligati equity companies.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undisco 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 commit were primarily associated with Upstream projects outside the U.S., of which $16.3 billion was associated with projects in Ca Australia, Africa, United Arab Emirates and Malaysia. The Corporation expects to fund the majority of these projects with inte generated funds that may be supplemented by long-term and short-term debt, including a revolving commercial paper program.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2013, for guarantees relating to n loans and performance under contracts (Note 16). Where guarantees for environmental remediation and other similar matters do not incl stated cap, the amounts reflect management's estimate of the maximum potential exposure. These guarantees are not reasonably likely to a material effect on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liqu 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 u 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 demonstrat Corporation's creditworthiness.

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

Management views the Corporation's financial strength, as evidenced by the above financial ratios and other similar measures, to competitive advantage of strategic importance. The Corporation's sound financial position gives it the opportunity to access the world's c markets in the full range of market conditions, and enables the Corporation to take on large, long-term capital commitments in the purs 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 numb pending lawsuits. Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outco any currently pending lawsuit against ExxonMobil will have a material adverse effect upon the Corporation's operations, financial cond or financial statements taken as a whole. There are no events or uncertainties beyond those already included in reported financial inform that would indicate a material change in future operating results or financial condition. Refer to Note 16 for additional information on proceedings and other contingencies.

CAPITAL AND EXPLORATION EXPENDITURES

	2013			2012		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	To
			(millions of dollars)			
Upstream *(1)*	9,145	29,086	38,231	11,080	25,004	36
Downstream	951	1,462	2,413	634	1,628	2
Chemical	963	869	1,832	408	1,010	1
Other	13	-	13	35	-	
Total	11,072	31,417	42,489	12,157	27,642	39

(1) Exploration expenses included.

Capital and exploration expenditures in 2013 were $42.5 billion, including $4.3 billion for acquisitions, as the Corporation continued to p opportunities to find and produce new supplies of oil and natural gas to meet global demand for energy. The Corporation anticipat average investment profile of about $37 billion per year for the next several years. Actual spending could vary depending on the progr 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 b were $1.2 billion higher than in 2012. Investments in 2013 included projects in the U.S. Gulf of Mexico and Alaska, exploration in Russi continued progress on world-class projects in Canada, Australia and Papua New Guinea. The majority of expenditures are on develop projects, which typically take two to four years from the time of recording proved undeveloped reserves to the start of production from reserves. The percentage of proved developed reserves was 66 percent of total proved reserves at year-end 2013, and has been over 60 pe 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 ref margin improvement project spending. The Chemical capital expenditures of $1.8 billion increased $0.4 billion from 2012 with h investments in the U.S., Saudi Arabia and China more than offsetting reduced spending on the completed Singapore Chemical Plant expar

TAXES

	2013	2012	20
		(millions of dollars)	
Income taxes	24,263	31,045	31
Effective income tax rate	*48%*	*44%*	
Sales-based taxes	30,589	32,409	33
All other taxes and duties	36,396	38,857	43
Total	91,248	102,311	108

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. In tax expense, both current and deferred, was $24.3 billion, $6.8 billion lower than 2012, with the impact of lower earnings partially offset b higher effective tax rate. The effective tax rate was 48 percent compared to 44 percent in the prior year due to the absence of favorab impacts on divestments. Sales-based and all other taxes and duties of $67.0 billion in 2013 decreased $4.3 billion reflecting the 2012 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. Incon expense, both current and deferred, was $31.0 billion, flat with 2011, with the impact of higher earnings offset by the lower effective tax 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-base all other taxes and duties of $71.3 billion in 2012 decreased $5.8 billion reflecting the Japan restructuring.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2013	20
	(millions of dollars)	
Capital expenditures	2,474	1
Other expenditures	3,538	3
Total	6,012	5

Throughout ExxonMobil’s businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels as well as proje monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions and expenditures for asset retirement obligations. definitions and guidelines established by the American Petroleum Institute, ExxonMobil’s 2013 worldwide environmental expenditures f such preventative and remediation steps, including ExxonMobil’s share of equity company expenditures, were about $6.0 billion. The tota 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 reaso estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for pro environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agenc identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at multiparty sites could mitigate ExxonMobil’s actual joint and several liability exposure. At present, no individual site is expected to have l material to ExxonMobil’s operations or financial condition. Consolidated company provisions made in 2013 for environmental liabilities $321 million ($391 million in 2012) and the balance sheet reflects accumulated liabilities of $773 million as of December 31, 2013 $841 million as of December 31, 2012.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2013	2012	
Crude oil and NGL ($/barrel)	97.48	100.29	1(
Natural gas ($/kcf)	4.60	3.90	

(1) Consolidated subsidiaries.

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In the Upstream, a $1 per barrel char the weighted-average realized price of oil would have approximately a $350 million annual after-tax effect on Upstream consolidatec equity company earnings. Similarly, a $0.10 per kcf change in the worldwide average gas realization would have approximately a $175 m annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detr will be dependent on the price movements of individual types of crude oil, taxes and other government take impacts, price adjustment la long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas 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 abs price levels of products sold. Refining margins are a function of the difference between what a refiner pays for its raw materials (prin crude oil) and the market prices for the range of products produced. These prices in turn depend on global and regional supply/de balances, inventory levels, refinery operations, import/export balances and weather.

The global energy markets can give rise to extended periods in which market conditions are adverse to one or more of the Corpora businesses. Such conditions, along with the capital-intensive nature of the industry and very long lead times associated with many c projects, underscore the importance of maintaining a strong financial position. Management views the Corporation’s financial strengtl competitive advantage.

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where sales take place, they are the result of efficiencies and competitive advantages of integrated refinery/chemical complexes. Additio intersegment sales are at market-based prices. The products bought and sold between segments can also be acquired in worldwide market have substantial liquidity, capacity and transportation capabilities. About 35 percent of the Corporation’s intersegment sales are cru produced by the Upstream and sold to the Downstream. Other intersegment sales include those between refineries and chemical plants r 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, (actions and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingl Corporation tests the viability of all of its investments over a broad range of future prices. The Corporation’s assessment is that its opera will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment and asset management prog

The Corporation has an active asset management program in which underperforming assets are either improved to acceptable lev considered for divestment. The asset management program includes a disciplined, regular review to ensure that all assets are contributing Corporation’s strategic objectives. The result is an efficient capital base, and the Corporation has seldom had to write down the carrying 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, Downstrean Chemical businesses reduce the Corporation’s enterprise-wide risk from changes in interest rates, currency rates and commodity prices. result, the Corporation makes limited use of derivative instruments to mitigate the impact of such changes. With respect to deriv activities, the Corporation believes that there are no material market or credit risks to the Corporation’s financial position, results of opera or liquidity as a result of the derivatives described in Note 13. The Corporation does not engage in speculative derivative activiti derivative trading activities nor does it use derivatives with leveraged features. Credit risk associated with the Corporation’s derivative po is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on deri counterparties. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative acti

The Corporation is exposed to changes in interest rates, primarily on its short-term debt and the portion of long-term debt that c floating interest rates. The impact of a 100-basis-point change in interest rates affecting the Corporation’s debt would not be mater earnings, cash flow or fair value. The Corporation has access to significant capacity of long-term and short-term liquidity. Internally gen funds are expected to cover the majority of financial requirements, and may be supplemented by long-term and short-term debt, incluc revolving commercial paper program. Some joint-venture partners are dependent on the credit markets, and their funding ability may i 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, exp financing and investment transactions. The impacts of fluctuations in exchange rates on ExxonMobil’s geographically and functionally di operations are varied and often offsetting in amount. The Corporation makes limited use of currency exchange contracts to mitigate the i 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 imp non-energy costs has generally been mitigated by cost reductions from efficiency and productivity improvements. Increased demand for c services and materials has resulted in higher operating and capital costs in recent years. The Corporation works to counter upward press costs through its economies of scale in global procurement and its efficient project management practices.

CRITICAL ACCOUNTING ESTIMATES

The Corporation's accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refinin marketing of hydrocarbons and hydrocarbon-based products. The preparation of financial statements in conformity with U.S. Gen Accepted Accounting Principles (GAAP) requires management to make estimates and judgments that affect the reported amounts of a liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The Corporation's accounting policies are summa 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 inves decisions about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the ba 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, whic analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible. Unproved reserv those with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that are more lik be recovered than not.

The estimation of proved reserves is an ongoing process based on rigorous technical evaluations, commercial and market assessmen detailed analysis of well information such as flow rates and reservoir pressure declines. The estimation of proved reserves is controlled b Corporation through long-standing approval guidelines. Reserve changes are made within a well-established, disciplined process driv senior level geoscience and engineering professionals, assisted by the Reserves Technical Oversight group which has significant tecl experience, culminating in reviews with and approval by senior management. Notably, the Corporation does not use specific quanti 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 affectec number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in term oil and gas price levels.

Proved reserves can be further subdivided into developed and undeveloped reserves. The percentage of proved developed reserves w percent of total proved reserves at year-end 2013 (including both consolidated and equity company reserves), and has been over 60 perce 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 t evaluation or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production da (3) changes in prices and year-end costs that are used in the estimation of reserves. Revisions can also result from significant chang 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 estimat measures the depreciation of upstream assets. It is the ratio of actual volumes produced to total proved developed reserves (those p reserves recoverable through existing wells with existing equipment and operating methods), applied to the asset cost. The volumes proc and asset cost are known and, while proved developed reserves have a high probability of recoverability, they are based on estimates th subject to some variability. While the revisions the Corporation has made in the past are an indicator of variability, they have had a very 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 Corporatic reviewed for impairment whenever events or circumstances indicate that the carrying amounts may not be recoverable. Assets are grouı 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 amo Impairment analyses are generally based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of reserves may be included in the impairment evaluation. An asset group would be impaired if its undiscounted cash flows were less tha 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 cost recorded based on the estimated economic chance of success and the length of time that the Corporation expects to hold the prope Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding pe

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses assi Corporation in assessing whether the carrying amounts of any of its assets may not be recoverable. In addition to estimating oil and gas re volumes in conducting these analyses, it is also necessary to estimate future oil and gas prices. Potential trigger events for impai evaluation include a significant decrease in current and projected reserve volumes, an accumulation of project costs significantly in exc 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 markets for crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop significantly, inc prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an i on world oil supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus de 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 a planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same assumptions that are used for capital investment decisions. Volumes are based on field production profiles, which are updated annually. 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 no consolidated financial statements. Future prices used for any impairment tests will vary from the ones used in the supplemental oil an 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 disco basis, which is typically at the time the assets are installed. In the estimation of fair value, the Corporation uses assumptions and judg regarding such factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; esti amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations are disclosed in Note 9 to the fin statements.

Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justi completion as a producing well and the Corporation is making sufficient progress assessing the reserves and the economic and ope viability of the project. Exploratory well costs not meeting these criteria are charged to expense. The facts and circumstances that su 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 includ Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses. Amounts representin Corporation's interest in the underlying net assets of other significant entities that it does not control, but over which it exercises signi 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 to balance worldwide risks, and in others they provide the only available means of entry into a particular market or area of interest. The parties who also have an equity interest in these companies are either independent third parties or host governments that share in the bu results according to their ownership. The Corporation does not invest in these companies in order to remove liabilities from its balance In fact, the Corporation has long been on record supporting an alternative accounting method that would require each investor to consolid share of all assets and liabilities in these partially owned companies rather than only its interest in net equity. This method of accountir investments in partially-owned companies is not permitted by U.S. GAAP except where the investments are in the direct ownership of a of upstream assets and liabilities. However, for purposes of calculating return on average capital employed, which is not covered by GAAP standards, the Corporation includes its share of debt of these partially-owned companies in the determination of average c employed.

Pension Benefits

The Corporation and its affiliates sponsor over 100 defined benefit (pension) plans in about 50 countries. Pension and Other Postretire 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 flow rather than a separate pension fund. Book reserves are established for these plans because tax conventions and regulatory practices c encourage advance funding. The portion of the pension cost attributable to employee service is expensed as services are rendered. The p attributable to the increase in pension obligations due to the passage of time is expensed over the term of the obligations, which ends wh benefits are paid. The primary difference in pension expense for unfunded versus funded plans is that pension expense for funded plan 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 insu arrangements. These plans are managed in compliance with the requirements of governmental authorities and meet or exceed required fu levels as measured by relevant actuarial and government standards at the mandated measurement dates. In determining liabilities and rec 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, rega of the funding status of the underlying plans, are fully supported by the financial strength of the Corporation or the respective spons affiliate.

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the dis rate for the benefit obligations and the long-term rate for future salary increases. Pension assumptions are reviewed annually by ou actuaries and senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long 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 assets were 7 percent and 9 percent, respectively. The Corporation establishes the long-term expected rate of return by developing a for looking, long-term return assumption for each pension fund asset class, taking into account factors such as the expected real return fo specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allo percentages and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the long-term rate of retu 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 yea the difference occurs. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense 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 law Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accou 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 c reasonably estimated. These amounts are not reduced by amounts that may be recovered under insurance or claims against third partie undiscounted receivables from insurers or other third parties may be accrued separately. The Corporation revises such accruals in light o information. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation disclos nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of our litigation contingency disclo "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 pr However, the Corporation has been successful in defending litigation in the past. Payments have not had a material adverse effect on oper or financial condition. In the Corporation's experience, large claims often do not result in large awards. Large awards are often revers 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 i 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 i financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the la amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken or exp to be taken in an income tax return and the amount recognized in the financial statements. The Corporation’s unrecognized tax benefits 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. doll prescribed by GAAP. Under these principles, it is necessary to select the functional currency of these subsidiaries. The functional curren the currency of the primary economic environment in which the subsidiary operates. Management selects the functional currency evaluating this economic environment.

Factors considered by management when determining the functional currency for a subsidiary include the currency used for cash related to individual assets and liabilities; the responsiveness of sales prices to changes in exchange rates; the history of inflation i country; whether sales are into local markets or exported; the currency used to acquire raw materials, labor, services and supplies; sourc 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 respo for establishing and maintaining adequate internal control over the Corporation’s financial reporting. Management conducted an evaluati the effectiveness of internal control over financial reporting based on criteria established in *Internal Control – Integrated Framework (* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management conclude 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 in 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	Andrew P. Swiger	Patrick T. Mulva
Chief Executive Officer	Senior Vice President	Vice President and Controller
	(Principal Financial Officer)	(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 In Changes in Equity and Cash Flows present fairly, in all material respects, the financial position of Exxon Mobil Corporation a 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 p ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also in our op the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, bas criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Trea Commission (COSO). The Corporation's management is responsible for these financial statements, for maintaining effective internal c over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompa Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statemen on the Corporation's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance wi standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the au obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal c over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant esti made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial rep included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and t and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing 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 reliabil financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accou principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenar records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) pr reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with gen accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizati management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unautho 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 o evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditio 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	201
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*		420,836	451,509	467
Income from equity affiliates	7	13,927	15,010	15
Other income		3,492	14,162	4
Total revenues and other income		438,255	480,681	486
Costs and other deductions				
Crude oil and product purchases		244,156	263,535	266
Production and manufacturing expenses		40,525	38,521	40
Selling, general and administrative expenses		12,877	13,877	14
Depreciation and depletion		17,182	15,888	15
Exploration expenses, including dry holes		1,976	1,840	2
Interest expense		9	327	
Sales-based taxes *(1)*	19	30,589	32,409	33
Other taxes and duties	19	33,230	35,558	39
Total costs and other deductions		380,544	401,955	413
Income before income taxes		57,711	78,726	73
Income taxes	19	24,263	31,045	31
Net income including noncontrolling interests		33,448	47,681	42
Net income attributable to noncontrolling interests		868	2,801	1
Net income attributable to ExxonMobil		32,580	44,880	41
Earnings per common share *(dollars)*	12	7.37	9.70	
Earnings per common share - assuming dilution *(dollars)*	12	7.37	9.70	

(1) Sales and other operating revenue includes sales-based taxes of $30,589 million for 2013, $32,409 million for 2012 and $33,503 m 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	201
		(millions of dollars)	
Net income including noncontrolling interests	33,448	47,681	42
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(3,620)	920	
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
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	1,820	2,395	1
Change in fair value of cash flow hedges	-	-	
Realized (gain)/loss from settled cash flow hedges included in net income	-	-	
Total other comprehensive income	1,351	(4,611)	(4
Comprehensive income including noncontrolling interests	34,799	43,070	37
Comprehensive income attributable to noncontrolling interests	760	1,251	
Comprehensive income attributable to ExxonMobil	34,039	41,819	36

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2013	Dec. 3 2012
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		4,644	9
Cash and cash equivalents - restricted		269	
Notes and accounts receivable, less estimated doubtful amounts	6	33,152	34
Inventories			
Crude oil, products and merchandise	3	12,117	10
Materials and supplies		4,018	3
Other current assets		5,108	5
Total current assets		59,308	64
Investments, advances and long-term receivables	8	36,328	34
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	243,650	226
Other assets, including intangibles, net		7,522	7
Total assets		346,808	333
Liabilities			
Current liabilities			
Notes and loans payable	6	15,808	3
Accounts payable and accrued liabilities	6	48,085	50
Income taxes payable		7,831	9
Total current liabilities		71,724	64
Long-term debt	14	6,891	7
Postretirement benefits reserves	17	20,646	25
Deferred income tax liabilities	19	40,530	37
Long-term obligations to equity companies		4,742	3
Other long-term obligations		21,780	23
Total liabilities		166,313	162
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		10,077	9
Earnings reinvested		387,432	365
Accumulated other comprehensive income		(10,725)	(12
Common stock held in treasury (3,684 million shares in 2013 and 3,517 million shares in 2012)		(212,781)	(197
ExxonMobil share of equity		174,003	165
Noncontrolling interests		6,492	5
Total equity		180,495	171
Total liabilities and equity		346,808	333

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
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		33,448	47,681	42
Adjustments for noncash transactions				
Depreciation and depletion		17,182	15,888	15
Deferred income tax charges/(credits)		754	3,142	
Postretirement benefits expense in excess of/(less than) net payments		2,291	(315)	
Other long-term obligation provisions in excess of/(less than) payments		(2,566)	1,643	
Dividends received greater than/(less than) equity in current earnings of equity companies		3	(1,157)	
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		(305)	(1,082)	(7
- Inventories		(1,812)	(1,873)	(2
- Other current assets		(105)	(42)	
Increase/(reduction) - Accounts and other payables		(2,498)	3,624	8
Net (gain) on asset sales	5	(1,828)	(13,018)	(2
All other items - net		350	1,679	1
Net cash provided by operating activities		44,914	56,170	55
Cash flows from investing activities				
Additions to property, plant and equipment		(33,669)	(34,271)	(30
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	5	2,707	7,655	11
Decrease/(increase) in restricted cash and cash equivalents		72	63	
Additional investments and advances		(4,435)	(598)	(3
Collection of advances		1,124	1,550	1
Additions to marketable securities		-	-	(1
Sales of marketable securities		-	-	1
Net cash used in investing activities		(34,201)	(25,601)	(22
Cash flows from financing activities				
Additions to long-term debt		345	995	
Reductions in long-term debt		(13)	(147)	
Additions to short-term debt		16	958	1
Reductions in short-term debt		(756)	(4,488)	(1
Additions/(reductions) in debt with three months or less maturity		12,012	(226)	1
Cash dividends to ExxonMobil shareholders		(10,875)	(10,092)	(9
Cash dividends to noncontrolling interests		(304)	(327)	
Changes in noncontrolling interests		(1)	204	
Tax benefits related to stock-based awards		48	130	
Common stock acquired		(15,998)	(21,068)	(22
Common stock sold		50	193	
Net cash used in financing activities		(15,476)	(33,868)	(28
Effects of exchange rate changes on cash		(175)	217	
Increase/(decrease) in cash and cash equivalents		(4,938)	(3,082)	4
Cash and cash equivalents at beginning of year		9,582	12,664	7
Cash and cash equivalents at end of year		4,644	9,582	12

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						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	To[illegible] Eq[illegible]
	(millions of dollars)						
Balance as of December 31, 2010	9,371	298,899	(4,823)	(156,608)	146,839	5,840	[illegible]
Amortization of stock-based awards	742	-	-	-	742	-	
Tax benefits related to stock-based awards	202	-	-	-	202	-	
Other	(803)	-	-	-	(803)	(5)	
Net income for the year	-	41,060	-	-	41,060	1,146	[illegible]
Dividends - common shares	-	(9,020)	-	-	(9,020)	(306)	[illegible]
Other comprehensive income	-	-	(4,300)	-	(4,300)	(312)	[illegible]
Acquisitions, at cost	-	-	-	(22,055)	(22,055)	(15)	[illegible]
Dispositions	-	-	-	1,731	1,731	-	
Balance as of December 31, 2011	9,512	330,939	(9,123)	(176,932)	154,396	6,348	[illegible]
Amortization of stock-based awards	806	-	-	-	806	-	
Tax benefits related to stock-based awards	178	-	-	-	178	-	
Other	(843)	-	-	-	(843)	(1,441)	[illegible]
Net income for the year	-	44,880	-	-	44,880	2,801	[illegible]
Dividends - common shares	-	(10,092)	-	-	(10,092)	(327)	[illegible]
Other comprehensive income	-	-	(3,061)	-	(3,061)	(1,550)	
Acquisitions, at cost	-	-	-	(21,068)	(21,068)	(34)	[illegible]
Dispositions	-	-	-	667	667	-	
Balance as of December 31, 2012	9,653	365,727	(12,184)	(197,333)	165,863	5,797	[illegible]
Amortization of stock-based awards	761	-	-	-	761	-	
Tax benefits related to stock-based awards	162	-	-	-	162	-	
Other	(499)	-	-	-	(499)	240	
Net income for the year	-	32,580	-	-	32,580	868	[illegible]
Dividends - common shares	-	(10,875)	-	-	(10,875)	(304)	[illegible]
Other comprehensive income	-	-	1,459	-	1,459	(108)	
Acquisitions, at cost	-	-	-	(15,998)	(15,998)	(1)	[illegible]
Dispositions	-	-	-	550	550	-	
Balance as of December 31, 2013	10,077	387,432	(10,725)	(212,781)	174,003	6,492	[illegible]

Common Stock Share Activity	Issued	Held in Treasury	Outstan[illegible]
		(millions of shares)	
Balance as of December 31, 2010	8,019	(3,040)	[illegible]
Acquisitions	-	(278)	
Dispositions	-	33	
Balance as of December 31, 2011	8,019	(3,285)	[illegible]
Acquisitions	-	(244)	
Dispositions	-	12	
Balance as of December 31, 2012	8,019	(3,517)	[illegible]
Acquisitions	-	(177)	
Dispositions	-	10	
Balance as of December 31, 2013	8,019	(3,684)	[illegible]

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

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

The Corporation's principal business is energy, involving the worldwide exploration, production, transportation and sale of crude o natural gas (Upstream) and the manufacture, transportation and sale of petroleum products (Downstream). The Corporation is also a 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 managem make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent asset liabilities. Actual results could differ from these estimates. Prior years' data has been reclassified in certain cases to conform to the presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation. The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls. They 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 influenc included in "Investments, advances and long-term receivables." The Corporation's share of the net income of these companies is incluc 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 f may indicate that a majority-owned investment is not controlled and therefore should be accounted for using the equity method of accou These factors occur where the minority shareholders are granted by law or by contract substantive participating rights. These include the 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 report Accumulated Other Comprehensive Income.

Evidence of loss in value that might indicate impairment of investments in companies accounted for on the equity method is assess determine if such evidence represents a loss in value of the Corporation's investment that is other than temporary. Examples of key indi include a history of operating losses, a negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, a financial condition and prospects for the investee's business segment or geographic region. If evidence of an other than temporary loss i value below carrying amount is determined, an impairment is recognized. In the absence of market prices for the investment, discounted flows are used to assess fair value.

Revenue Recognition. The Corporation generally sells crude oil, natural gas and petroleum and chemical products under short agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic adjustments. Revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assume 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 c basis of the Corporation's net working interest. Differences between actual production and net working interest volumes are not significan

Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another are combine 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 Consoli 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 specu derivative activities or derivative trading activities, nor does it use derivatives with leveraged features. When the Corporation does ente derivative transactions, it is to offset exposures associated with interest rates, foreign currency exchange rates and hydrocarbon prices that 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 Corpo designates derivatives as fair value hedges, in which case the gains and losses are offset in income by the gains and losses arising from ch 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 m participants. Hierarchy Levels 1, 2 and 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy

Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or lia 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 deter under the last-in, first-out method – LIFO). Inventory costs include expenditures and other charges (including depreciation) directl indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative exp 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 asse primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset servic taking obsolescence into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. I 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 hist cost of acquiring the constructed assets. The project construction phase commences with the development of the detailed engineering d and ends when the constructed assets are ready for their intended use. Capitalized interest costs are included in property, plant and equip 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, cos accumulated on a field-by-field basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred. Co 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 comp as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viabil the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geoph 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 an reserves.

Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using of-production rates based on the amount of proved developed reserves of oil, gas and other minerals that are estimated to be recoverable 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 met 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 production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incur operate and maintain the Corporation’s wells and related equipment and facilities and are expensed as incurred. They become part of th of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labor costs to operate the wells and r equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the well 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 circumst indicate that the carrying amounts may not be recoverable. Assets are grouped at the lowest level for which there are identifiable cash 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 am Cash flows used in impairment evaluations are developed using annually updated corporate plan investment evaluation assumptions for oil commodity prices, refining and chemical margins and foreign currency exchange rates. Annual volumes are based on field produ profiles, which are also updated annually. Prices for natural gas and other products are based on corporate plan assumptions deve annually by major region and also for investment evaluation purposes. Cash flow estimates for impairment testing exclude deri instruments.

Impairment analyses are generally based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of reserves may be included in the impairment evaluation. An asset group would be impaired if the undiscounted cash flows were less th 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 cost recorded based on the estimated economic chance of success and the length of time that the Corporation expects to hold the prop Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding p The valuation allowances are reviewed at least annually.

Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of 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 i than the carrying value.

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

Liabilities for environmental costs are recorded when it is probable that obligations have been incurred and the amounts can be reaso 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 o 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 inflation (primarily in Latin America) and Singapore, which predominantly sells into the U.S. dollar export market. Upstream operations w are relatively self-contained and integrated within a particular country, such as Canada, the United Kingdom, Norway and continental Eu use the local currency. Some Upstream operations, primarily in Asia and Africa, use the U.S. dollar because they predominantly sell crud 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 units. Compensation expense is measured by the price of the stock at the date of grant and is recognized in income over the requisite se 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.

Net income included before-tax aggregate foreign exchange transaction gains of $155 million and $159 million, and losses of $184 m 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 t combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to e: 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
	(billions of dollars)
Petroleum products	3.9
Crude oil	4.7
Chemical products	2.9
Gas/other	0.6
Total	12.1

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	Cumulative Foreign Exchange Translation Adjustment	Post-retirement Benefits Reserves Adjustment	Unrealized Change in Fair Value on Cash Flow Hedges	Total
		(millions of dollars)		
Balance as of December 31, 2010	5,011	(9,889)	55	(4,8
Current period change excluding amounts reclassified from accumulated other comprehensive income	(843)	(4,557)	28	(5,3
Amounts reclassified from accumulated other comprehensive income	-	1,155	(83)	1,0
Total change in accumulated other comprehensive income	(843)	(3,402)	(55)	(4,3
Balance as of December 31, 2011	4,168	(13,291)	-	(9,1
Balance as of December 31, 2011	4,168	(13,291)	-	(9,1
Current period change excluding amounts reclassified from accumulated other comprehensive income	842	(3,402)	-	(2,5
Amounts reclassified from accumulated other comprehensive income	(2,600)	2,099	-	(5
Total change in accumulated other comprehensive income	(1,758)	(1,303)	-	(3,0
Balance as of December 31, 2012	2,410	(14,594)	-	(12,1
Balance as of December 31, 2012	2,410	(14,594)	-	(12,1
Current period change excluding amounts reclassified from accumulated other comprehensive income	(3,233)	2,963	-	(2
Amounts reclassified from accumulated other comprehensive income	(23)	1,752	-	1,7
Total change in accumulated other comprehensive income	(3,256)	4,715	-	1,4
Balance as of December 31, 2013	(846)	(9,879)	-	(10,7

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)	2013	2012	20
		(millions of dollars)	
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
Realized gain from settled cash flow hedges included in net income (Statement of Income line: Sales and other operating revenue)	-	-	

(1) These accumulated other comprehensive income components are included in the computation of net periodic pension cost. (See Not – Pension and Other Postretirement Benefits for additional details.)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	2013	2012	20
		(millions of dollars)	
Foreign exchange translation adjustment	218	(236)	
Postretirement benefits reserves adjustment			
Postretirement benefits reserves adjustment (excluding amortization)	(1,540)	1,619	2
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(796)	(1,226)	
Unrealized change in fair value on cash flow hedges			
Change in fair value of cash flow hedges	-	-	
Settled cash flow hedges included in net income	-	-	
Total	(2,118)	157	1

5. Cash Flow Information

The Consolidated Statement of Cash Flows provides information about changes in cash and cash equivalents. Highly liquid investments 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 be 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 the Japan restructuring, the sale of an Upstream property in Angola, exchanges of Upstream properties, the sale of U.S. service stations the sale of the Downstream affiliates in Malaysia and Switzerland in 2012; and from the sale of some Upstream Canadian, U.K. and producing properties and assets, and the sale of U.S. service stations in 2011. These gains are reported in “Other income” on the Consoli 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 I Services (Bahamas) Ltd. was assigned to a consolidated ExxonMobil affiliate. This note is no longer classified as third party long-term 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 inc in the “Sales of subsidiaries, investments, and property, plant and equipment” or the “Additions to property, plant and equipment” lines c Statement of Cash Flows.

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

	2013	2012	2(
		(millions of dollars)	
Cash payments for interest	426	555	
Cash payments for income taxes	25,066	24,349	2;

6. Additional Working Capital Information

	Dec. 31 2013	De 2(
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $112 million and $109 million	25,993	2٤
Other, less reserves of $28 million and $36 million	7,159	(
Total	33,152	3‹
Notes and loans payable		
Bank loans	722	
Commercial paper	14,051	1
Long-term debt due within one year	1,034	1
Other	1	
Total	15,808	ː
Accounts payable and accrued liabilities		
Trade payables	30,920	3ː
Payables to equity companies	6,587	(
Accrued taxes other than income taxes	3,883	‹
Other	6,695	(
Total	48,085	5(

The Corporation has short-term committed lines of credit of $5.9 billion which were unused as of December 31, 2013. The majority of lines are available for general corporate purposes, however $0.5 billion has been designated as specifically supporting commercial programs. The weighted-average interest rate on short-term borrowings outstanding was 0.4 percent and 1.7 percent at December 31, 201ː 2012, respectively.

7. Equity Company Information

The summarized financial information below includes amounts related to certain less-than-majority-owned companies and majority-o subsidiaries where minority shareholders possess the right to participate in significant management decisions (see Note 1). These comp are primarily engaged in oil and gas exploration and production, natural gas marketing and refining operations in North America; natur exploration, production and distribution, and downstream operations in Europe; and research, exploration, production, liquefied natur (LNG) operations, refining operations, petrochemical manufacturing, fuel sales and power generation in Asia. Also included are se 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 partner Differences between the company's carrying value of an equity investment and its underlying equity in the net assets of the affilia assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the factors giving rise to the differ 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 perc the years 2013, 2012 and 2011, respectively.

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

Equity Company Financial Summary	2013 Total	2013 ExxonMobil Share	2012 Total	2012 ExxonMobil Share	2011 Total	2011 ExxonM Sha
			(millions of dollars)			
Total revenues	236,161	68,084	224,953	67,572	204,635	65
Income before income taxes	69,454	19,999	69,411	20,882	68,908	20
Income taxes	21,618	6,069	20,703	5,868	19,812	5
Income from equity affiliates	47,836	13,930	48,708	15,014	49,096	15
Current assets	62,398	19,545	59,612	18,483	52,879	17
Long-term assets	116,450	35,695	111,131	33,798	96,908	30
Total assets	178,848	55,240	170,743	52,281	149,787	48
Current liabilities	54,550	15,243	49,698	14,265	41,016	12
Long-term liabilities	68,857	20,873	68,855	19,715	62,472	18
Net assets	55,441	19,124	52,190	18,301	46,299	16

A list of significant equity companies as of December 31, 2013, together with the Corporation’s percentage ownership interest, is de 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 20
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	19,619	18
Advances	10,476	9
Total equity company investments and advances	30,095	28
Companies carried at cost or less and stock investments carried at fair value	115	
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $2,938 million and $2,499 million	6,118	5
Total	36,328	34

9. Property, Plant and Equipment and Asset Retirement Obligations

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

In the Upstream segment, depreciation is generally on a unit-of-production basis, so depreciable life will vary by field. In the Downs segment, investments in refinery and lubes basestock manufacturing facilities are generally depreciated on a straight-line basis over a 25 life and service station buildings and fixed improvements over a 20-year life. In the Chemical segment, investments in process equipme 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. In 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 disco basis, which is typically at the time the assets are installed. In the estimation of fair value, the Corporation uses assumptions and judg regarding such factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; esti amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations incurred in the current period were Le (unobservable inputs) fair value measurements. The costs associated with these liabilities are capitalized as part of the related asset 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 down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites indeterminate lives based on plans for continued operations and as such, the fair value of the conditional legal obligations cannot be meas 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	
	(millions of dollars)	
Beginning balance	11,973	10
Accretion expense and other provisions	785	
Reduction due to property sales	(97)	
Payments made	(664)	
Liabilities incurred	603	
Foreign currency translation	(344)	
Revisions	732	1
Ending balance	12,988	11

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 justi completion as a producing well and the Corporation is making sufficient progress assessing the reserves and the economic and ope viability of the project. The term “project” as used in this report can refer to a variety of different activities and does not necessarily hav 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 summa those costs.

Change in capitalized suspended exploratory well costs:

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

Period end capitalized suspended exploratory well costs:

	2013	2012	
		(millions of dollars)	
Capitalized for a period of one year or less	293	866	
Capitalized for a period of between one and five years	1,705	1,176	1
Capitalized for a period of between five and ten years	470	401	
Capitalized for a period of greater than ten years	239	236	
Capitalized for a period greater than one year - subtotal	2,414	1,813	2
Total	2,707	2,679	2

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

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

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

Country/Project	Dec. 31, 2013	Years Wells Drilled	Comment
	(millions of dollars)		
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.
- 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		

11. Leased Facilities

At December 31, 2013, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering d equipment, tankers, service stations and other properties with minimum undiscounted lease commitments totaling $7,438 million as indi in the table. Estimated related rental income from noncancelable subleases is $95 million.

	Lease Payments Under Minimum Commitments	Related Sublease Rental Income
	(millions of dollars)	
2014	2,391	33
2015	1,724	29
2016	1,036	7
2017	481	5
2018	289	2
2019 and beyond	1,517	19
Total	7,438	95

Net rental cost under both cancelable and noncancelable operating leases incurred during 2013, 2012 and 2011 were as follows:

	2013	2012	
		(millions of dollars)	
Rental cost	3,841	3,851	4
Less sublease rental income	44	44	
Net rental cost	3,797	3,807	3

12. Earnings Per Share

	2013	2012	
Earnings per common share			
Net income attributable to ExxonMobil *(millions of dollars)*	32,580	44,880	41
Weighted average number of common shares outstanding *(millions of shares)*	4,419	4,628	4
Earnings per common share *(dollars)*	7.37	9.70	
Earnings per common share - assuming dilution			
Net income attributable to ExxonMobil *(millions of dollars)*	32,580	44,880	41
Weighted average number of common shares outstanding *(millions of shares)*	4,419	4,628	4
Effect of employee stock-based awards	-	-	
Weighted average number of common shares outstanding - assuming dilution	4,419	4,628	4
Earnings per common share - assuming dilution *(dollars)*	7.37	9.70	
Dividends paid per common share *(dollars)*	2.46	2.18	

13. Financial Instruments and Derivatives

Financial Instruments. The fair value of financial instruments is determined by reference to observable market data and other valu techniques as appropriate. The only category of financial instruments where the difference between fair value and recorded book va notable is long-term debt. The estimated fair value of total long-term debt, excluding capitalized lease obligations, was $6.8 billion anc billion at December 31, 2013, and 2012, respectively, as compared to recorded book values of $6.5 billion and $7.5 billion at Decembe 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 million. Level 1 represents quoted prices in active markets. Level 2 includes debt whose fair value is based upon a publicly available ir 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 Upst Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rate commodity prices. As a result, the Corporation makes limited use of derivatives to mitigate the impact of such changes. The Corporation not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. Whe Corporation does enter into derivative transactions, it is to offset exposures associated with interest rates, foreign currency exchange rate 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 yea 2013 and a net asset of $2 million at year-end 2012. Assets and liabilities associated with derivatives are usually recorded either in " 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 exchang 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 market-corroborated prices) inputs.

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of $(7) million, $(23) million and $131 m during 2013, 2012 and 2011, respectively. Income statement effects associated with derivatives are usually recorded either in "Sales and 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 liq as a result of the derivative activities described above.

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 equi at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $ million, which matures within one year and is included in current liabilities. The amounts of long-term debt maturing in each of the four 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
	(millions of dollars)	
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. billion supports commercial paper programs.

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of a Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are su to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less tha 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 i under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire or are settled in cash, do not count against this max limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unle Board terminates the plan early. At the end of 2013, remaining shares available for award under the 2003 Incentive Program were 117 mill

Restricted Stock and Restricted Stock Units. Awards totaling 9,729 thousand, 10,017 thousand, and 10,533 thousand of rest (nonvested) common stock and restricted (nonvested) common stock units were granted in 2013, 2012 and 2011, respectively. Compens 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 p Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be s transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior exec have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remainin percent of the award.

The Corporation has purchased shares in the open market and through negotiated transactions to offset shares issued in conjunction 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	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Shar**
	(thousands)	*(dollars)*
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**	
Grant price *(dollars)*	94.47	87.24	7
Value at date of grant:		*(millions of dollars)*	
Restricted stock and units settled in stock	843	797	
Units settled in cash	76	77	
Total value	919	874	

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

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

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 pe lawsuits. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accou recognition or disclosure of these contingencies. The Corporation accrues an undiscounted liability for those contingencies wher incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no ar within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Corporation does not r liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or whe liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possibl which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss purposes of our contingency disclosures, “significant” includes material matters as well as other matters which management believes shou disclosed. ExxonMobil will continue to defend itself vigorously in these matters. Based on a consideration of all relevant facts circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will h 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, 201 guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar m do not include a stated cap, the amounts reflect management’s estimate of the maximum potential exposure.

	Dec. 31, 2013		
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	3,086	46	3
Other	2,939	4,507	7
Total	6,025	4,553	10

(1) ExxonMobil share.

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

	Payments Due by Period			
	2014	**2015-2018**	**2019 and Beyond**	**T**
		(millions of dollars)		
Unconditional purchase obligations *(1)*	144	629	463	1

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

In accordance with a nationalization decree issued by Venezuela's president in February 2007, by May 1, 2007, a subsidiary of the Venez National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. This Project had been operated and o by ExxonMobil affiliates holding a 41.67 percent ownership interest in the Project. The decree also required conversion of the Cerro N Project into a "mixed enterprise" and an increase in PdVSA's or one of its affiliate's ownership interest in the Project, with the stipulatio if ExxonMobil refused to accept the terms for the formation of the mixed enterprise within a specified period of time, the government v "directly assume the activities" carried out by the joint venture. ExxonMobil refused to accede to the terms proffered by the governmen on June 27, 2007, the government expropriated ExxonMobil's 41.67 percent interest in the Cerro Negro Project. ExxonMobil's remainir 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 Inves Disputes (ICSID) invoking ICSID jurisdiction under Venezuela's Investment Law and the Netherlands-Venezuela Bilateral Investment T The ICSID Tribunal issued a decision on June 10, 2010, finding that it had jurisdiction to proceed on the basis of the Netherlands-Vene Bilateral Investment Treaty. The ICSID arbitration proceeding is continuing and a hearing on the merits was held in February 2012. A time, the net impact of these matters on the Corporation's consolidated financial results cannot be reasonably estimated. Regardles 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 Petro Corporation (NNPC) covering the Erha block located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the bloc 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 entitlement under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuja, Nigeria, the Nigerian Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholdin Contractors' position in all material respects and awarding damages to the Contractors jointly in an amount of approximately $1.8 billion $234 million in accrued interest. The Contractors petitioned a Nigerian federal court for enforcement of the award, and NNPC petitione 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 2013, the Contractors filed a lawsuit against NNPC in the Nigerian federal high court in order to preserve their ability to seek enforcem the PSC in the courts if necessary. At this time, the net impact of this matter on the Corporation's consolidated financial results cann reasonably estimated. However, regardless of the outcome of enforcement proceedings, the Corporation does not expect the proceedir have a material effect upon the Corporation's operations or financial condition.

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 Postretireme	
	U.S.		Non-U.S.		Benefits	
	2013	2012	2013	2012	2013	20
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	5.00	4.00	4.30	3.80	5.00	
Long-term rate of compensation increase	5.75	5.75	5.40	5.50	5.75	
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	19,779	17,035	28,670	29,068	9,058	7
Service cost	801	665	697	648	176	
Interest cost	749	820	1,076	1,145	352	
Actuarial loss/(gain)	(1,520)	2,553	(1,454)	2,335	(1,267)	1
Benefits paid *(1) (2)*	(2,520)	(1,294)	(1,311)	(1,330)	(511)	
Foreign exchange rate changes	-	-	(284)	651	(43)	
Japan restructuring and other divestments	-	-	(77)	(3,952)	-	
Plan amendments, other	15	-	40	105	103	
Benefit obligation at December 31	17,304	19,779	27,357	28,670	7,868	9
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, respective

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators ar discount rate determined by constructing a portfolio of high-quality, noncallable bonds with cash flows that match estimated outflov benefit payments. For major non-U.S. plans, the discount rate is determined by using bond portfolios with an average maturity approxim 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 201 subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $68 millio the postretirement benefit obligation by $734 million. A one-percentage-point decrease in the health care cost trend rate would decrease se and interest cost by $53 million and the postretirement benefit obligation by $597 million.

	Pension Benefits				Other Postretireme	
	U.S.		Non-U.S.		Benefits	
	2013	2012	2013	2012	2013	20
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	12,632	10,656	18,090	17,117	581	
Actual return on plan assets	617	1,457	1,604	1,541	64	
Foreign exchange rate changes	-	-	(270)	462	-	
Company contribution	101	1,560	919	1,604	35	
Benefits paid *(1)*	(2,171)	(1,041)	(869)	(922)	(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	

(1) Benefit payments for funded plans.

The funding levels of all qualified pension plans are in compliance with standards set by applicable law or regulation. As shown in the below, certain smaller U.S. pension plans and a number of non-U.S. pension plans are not funded because local tax conventions and regu practices do not encourage funding of these plans. All defined benefit pension obligations, regardless of the funding status of the unde 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	20
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(3,547)	(4,438)	(941)	(3
Unfunded plans	(2,567)	(2,709)	(7,133)	(7
Total	(6,114)	(7,147)	(8,074)	(10

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

	Pension Benefits				Other Postretireme	
	U.S.		Non-U.S.		Benefits	
	2013	2012	2013	2012	2013	20
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(6,114)	(7,147)	(8,074)	(10,580)	(7,248)	(8
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	1	1	201	49	-	
Current liabilities	(275)	(279)	(358)	(352)	(359)	
Postretirement benefits reserves	(5,840)	(6,869)	(7,917)	(10,277)	(6,889)	(8
Total recorded	(6,114)	(7,147)	(8,074)	(10,580)	(7,248)	(8
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	4,780	7,451	7,943	10,904	1,603	3
Prior service cost	60	67	665	758	65	
Total recorded in accumulated other comprehensive income	4,840	7,518	8,608	11,662	1,668	3

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

The long-term expected rate of return on funded assets shown below is established for each benefit plan by developing a forward-loo long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset clas inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the term return assumption for each asset class.

	Pension Benefits						Other Postretirement Benefits	
	U.S.			Non-U.S.				
	2013	2012	2011	2013	2012	2011	2013	2012
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					*(percent)*			
Discount rate	4.00	5.00	5.50	3.80	4.00	4.80	4.00	5.00
Long-term rate of return on funded assets	7.25	7.25	7.50	6.40	6.60	6.80	7.25	7.25
Long-term rate of compensation increase	5.75	5.75	5.25	5.50	5.40	5.20	5.75	5.75
Components of net periodic benefit cost					*(millions of dollars)*			
Service cost	801	665	546	697	648	574	176	134
Interest cost	749	820	792	1,076	1,145	1,267	352	380
Expected return on plan assets	(835)	(789)	(769)	(1,128)	(1,109)	(1,168)	(41)	(38)
Amortization of actuarial loss/(gain)	646	576	485	852	844	647	228	170
Amortization of prior service cost	7	7	9	117	117	103	21	34
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

(1) *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”.*

	U.S. 2013	U.S. 2012	U.S. 2011	Non-U.S. 2013	Non-U.S. 2012	Non-U.S. 2011	Other 2013	Other 2012
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
Amortization of actuarial (loss)/gain	(1,369)	(909)	(771)	(874)	(2,384)	(681)	(228)	(170)
Prior service cost/(credit)	-	-	-	30	71	187	-	-
Amortization of prior service (cost)/credit	(7)	(7)	(9)	(117)	(117)	(103)	(21)	(34)
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
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

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

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

	Total Pension and Other Postretirement Benefits		
	2013	**2012**	**20**
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	2,678	(969)	(1
Non-U.S. pension	3,054	253	(3
Other postretirement benefits	1,549	(807)	
Total (charge)/credit to other comprehensive income, before tax	7,281	(1,523)	(5
(Charge)/credit to income tax (see Note 4)	(2,336)	393	1
(Charge)/credit to investment in equity companies	49	(49)	
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	4,994	(1,179)	(3
Charge/(credit) to equity of noncontrolling interests	(279)	(124)	
(Charge)/credit to other comprehensive income attributable to ExxonMobil	4,715	(1,303)	(3

The Corporation's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in va asset classes and broad diversification to reduce the risk of the portfolio. The benefit plan assets are primarily invested in passive equit fixed income index funds to diversify risk while minimizing costs. The equity funds hold ExxonMobil stock only to the extent necess 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 benefit plans is 50 percent equity securities and 50 percent debt securities. The target asset allocation for the non-U.S. plans in aggregate percent equity securities and 51 percent debt securities. The equity targets for the U.S. and non-U.S. plans include an allocation to p 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 represe relative risk or credit quality of an investment.

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

(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 va treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active excho 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 incl Initial Public Offerings.

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

(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 treatec 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.

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

(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 va treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active excha 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 incl Initial Public Offerings.

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

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 below:

	2013			
	Pension			Other Postretireme
	U.S.	Non-U.S.		
	Private Equity	Private Equity	Real Estate	Private Equity
	(millions of dollars)			
Fair value at January 1	489	448	293	
Net realized gains/(losses)	(1)	11	(13)	
Net unrealized gains/(losses)	86	57	10	
Net purchases/(sales)	(51)	(14)	(154)	
Fair value at December 31	523	502	136	

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 Fair Value Measurement at December 31, 2012, Using:				Non-U.S. Pension Fair Value Measurement at December 31, 2012, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	T
				(millions of dollars)				
Asset category:								
Equity securities								
U.S.	-	2,600 *(1)*	-	2,600	-	2,671 *(1)*	-	2
Non-U.S.	-	3,227 *(1)*	-	3,227	203 *(2)*	5,308 *(1)*	-	5
Private equity	-	-	489 *(3)*	489	-	-	448 *(3)*	
Debt securities								
Corporate	-	3,872 *(4)*	-	3,872	-	2,005 *(4)*	-	2
Government	-	2,223 *(4)*	-	2,223	271 *(5)*	6,643 *(4)*	-	6
Asset-backed	-	10 *(4)*	-	10	-	100 *(4)*	-	
Real estate funds	-	-	-	-	-	-	293 *(6)*	
Cash	-	198 *(7)*	-	198	93	35 *(8)*	-	
Total at fair value	-	12,130	489	12,619	567	16,762	741	18
Insurance contracts at contract value				13				
Total plan assets				12,632				18

(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 va treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchc 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 incl Initial Public Offerings.

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

(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 treatec 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.

	Other Postretirement Fair Value Measurement at December 31, 2012, Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	T
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	-	166 (1)	-	
Non-U.S.	-	160 (1)	-	
Private equity	-	-	7 (2)	
Debt securities				
Corporate	-	91 (3)	-	
Government	-	136 (3)	-	
Asset-backed	-	14 (3)	-	
Cash	-	7	-	
Total at fair value	-	574	7	

(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 va treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchc 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 incl Initial Public Offerings.

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

The change in the fair value in 2012 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the below:

	2012 Pension U.S. Private Equity	Non-U.S. Private Equity	Non-U.S. Real Estate	Other Postretireme Private Equity
	(millions of dollars)			
Fair value at January 1	458	393	397	
Net realized gains/(losses)	2	2	(14)	
Net unrealized gains/(losses)	41	22	(1)	
Net purchases/(sales)	(12)	31	(89)	
Fair value at December 31	489	448	293	

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2013	2012	2013	20
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	14,737	17,070	891	9
Accumulated benefit obligation	12,342	14,171	689	8
Fair value of plan assets	11,189	12,631	611	7
For unfunded pension plans:				
Projected benefit obligation	2,567	2,709	7,133	7
Accumulated benefit obligation	1,647	1,731	6,070	6

	Pension Benefits		Other Postretirem Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2014 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	827	649	
Prior service cost *(2)*	8	122	

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

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

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Rece
	(millions of dollars)			
Contributions expected in 2014	1,400	800	-	
Benefit payments expected in:				
2014	1,540	1,279	458	
2015	1,520	1,293	473	
2016	1,501	1,348	485	
2017	1,467	1,383	496	
2018	1,387	1,423	505	
2019 - 2023	6,519	7,480	2,608	

18. Disclosures about Segments and Related Information

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

These functions have been defined as the operating segments of the Corporation because they are the segments (1) that engage in bus activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Corpora chief operating decision maker to make decisions about resources to be allocated to the segment and assess its performance; and (3) for discrete financial information is available.

Earnings after income tax include transfers at estimated market prices.

In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities. Interest ex includes non-debt-related interest expense of $202 million and $165 million in 2012 and 2011, respectively. For 2013, non-debt-related in expense was a net credit of $123 million, primarily reflecting the effect of credits from the favorable resolution of prior year tax positions.

	Upstream		Downstream		Chemical		Corporate and	Corp
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	Financing	T
				(millions of dollars)				
As of December 31, 2013								
Earnings after income tax	4,191	22,650	2,199	1,250	2,755	1,073	(1,538)	32
Earnings of equity companies above	1,576	11,627	(460)	22	189	1,422	(449)	13
Sales and other operating revenue *(1)*	13,712	25,349	123,802	218,904	15,295	23,753	21	420
Intersegment revenue	8,343	45,761	20,781	52,624	11,993	8,232	285	
Depreciation and depletion expense	5,170	8,277	633	1,390	378	632	702	17
Interest revenue	-	-	-	-	-	-	87	
Interest expense	30	26	7	8	1	-	(63)	
Income taxes	2,197	21,554	721	481	989	363	(2,042)	24
Additions to property, plant and equipment	7,480	26,075	616	1,072	840	272	1,386	37
Investments in equity companies	4,975	9,740	62	1,749	217	3,103	(227)	19
Total assets	88,698	157,465	19,261	40,661	7,816	19,659	13,248	346
As of December 31, 2012								
Earnings after income tax	3,925	25,970	3,575	9,615	2,220	1,678	(2,103)	44
Earnings of equity companies above	1,759	11,900	6	387	183	1,267	(492)	15
Sales and other operating revenue *(1)*	11,039	27,673	125,088	248,959	14,723	24,003	24	451
Intersegment revenue	8,764	47,507	20,963	62,130	12,409	9,750	258	
Depreciation and depletion expense	5,104	7,340	594	1,280	376	508	686	15
Interest revenue	-	-	-	-	-	-	117	
Interest expense	37	13	3	36	-	(1)	239	
Income taxes	2,025	25,362	1,811	1,892	755	232	(1,032)	31
Additions to property, plant and equipment	9,697	21,769	480	1,153	338	659	1,083	35
Investments in equity companies	4,020	9,147	195	2,069	233	3,143	(277)	18
Total assets	86,146	140,848	18,451	40,956	7,238	18,886	21,270	333
As of December 31, 2011								
Earnings after income tax	5,096	29,343	2,268	2,191	2,215	2,168	(2,221)	41
Earnings of equity companies above	2,045	11,768	7	353	198	1,365	(447)	15
Sales and other operating revenue *(1)*	14,023	32,419	120,844	257,779	15,466	26,476	22	467
Intersegment revenue	9,807	49,910	18,489	73,549	12,226	10,563	262	
Depreciation and depletion expense	4,879	7,021	650	1,560	380	458	635	15
Interest revenue	-	-	-	-	-	-	135	
Interest expense	30	36	10	24	2	(1)	146	
Income taxes	2,852	25,755	1,123	696	1,027	465	(867)	31
Additions to property, plant and equipment	10,887	18,934	400	1,334	241	910	932	33
Investments in equity companies	2,963	8,439	210	1,358	253	3,973	(228)	16
Total assets	82,900	127,977	18,354	51,132	7,245	19,862	23,582	331

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

Geographic

Sales and other operating revenue *(1)*	**2013**	**2012**	**201**
		(millions of dollars)	
United States	152,820	150,865	150
Non-U.S.	268,016	300,644	316
Total	420,836	451,509	467
Significant non-U.S. revenue sources include:			
Canada	35,924	34,325	34
United Kingdom	34,061	33,600	34
Belgium	20,973	23,567	26
Italy	19,273	18,228	16
France	18,444	19,601	18
Germany	15,701	15,871	17
Singapore	15,623	14,606	14
Japan	124	14,162	31

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

Long-lived assets	**2013**	**2012**	**201**
		(millions of dollars)	
United States	98,271	94,336	91
Non-U.S.	145,379	132,613	123
Total	243,650	226,949	214
Significant non-U.S. long-lived assets include:			
Canada	41,522	31,979	24
Australia	14,258	13,415	9
Nigeria	12,343	12,216	11
Singapore	9,570	9,700	9
Kazakhstan	8,530	7,785	7
Angola	8,262	8,238	10
Norway	6,542	7,040	6
Papua New Guinea	5,768	4,599	3

19. Income, Sales-Based and Other Taxes

	2013			2012			2011		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	To
					(millions of dollars)				
Income tax expense									
Federal and non-U.S.									
Current	1,073	22,115	23,188	1,791	25,650	27,441	1,547	28,849	30
Deferred - net	(116)	757	641	1,097	1,816	2,913	1,577	(1,417)	
U.S. tax on non-U.S. operations	37	-	37	89	-	89	15	-	
Total federal and non-U.S.	994	22,872	23,866	2,977	27,466	30,443	3,139	27,432	30
State	397	-	397	602	-	602	480	-	
Total income tax expense	1,391	22,872	24,263	3,579	27,466	31,045	3,619	27,432	31
Sales-based taxes	5,992	24,597	30,589	5,785	26,624	32,409	5,652	27,851	33
All other taxes and duties									
Other taxes and duties	955	32,275	33,230	1,406	34,152	35,558	1,539	38,434	39
Included in production and manufacturing expenses	1,318	1,182	2,500	1,242	1,308	2,550	1,342	1,425	2
Included in SG&A expenses	150	516	666	154	595	749	181	623	
Total other taxes and duties	2,423	33,973	36,396	2,802	36,055	38,857	3,062	40,482	43
Total	9,806	81,442	91,248	12,166	90,145	102,311	12,333	95,765	108

All other taxes and duties include taxes reported in production and manufacturing and selling, general and administrative (SG&A) expe The above provisions for deferred income taxes include net credits of $310 million in 2013 and $330 million in 2011 and a net charge of million in 2012 for the effect of changes in tax laws and rates.

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2013, 201 2011 is as follows:

	2013	2012	20
		(millions of dollars)	
Income before income taxes			
United States	9,746	11,222	1
Non-U.S.	47,965	67,504	61
Total	57,711	78,726	73
Theoretical tax	20,199	27,554	25
Effect of equity method of accounting	(4,874)	(5,254)	(5
Non-U.S. taxes in excess of theoretical U.S. tax	10,528	8,434	10
U.S. tax on non-U.S. operations	37	89	
State taxes, net of federal tax benefit	258	391	
Other	(1,885)	(169)	
Total income tax expense	24,263	31,045	31
Effective tax rate calculation			
Income taxes	24,263	31,045	31
ExxonMobil share of equity company income taxes	6,061	5,859	5
Total income taxes	30,324	36,904	36
Net income including noncontrolling interests	33,448	47,681	42
Total income before taxes	63,772	84,585	78
Effective income tax rate	48%	44%	

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

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

Tax effects of temporary differences for:	**2013**	**20**
	(millions of dollars)	
Property, plant and equipment	50,884	48
Other liabilities	3,474	3
Total deferred tax liabilities	54,358	52
Pension and other postretirement benefits	(6,573)	(8
Asset retirement obligations	(6,083)	(5
Tax loss carryforwards	(3,393)	(2
Other assets	(6,246)	(6
Total deferred tax assets	(22,295)	(22
Asset valuation allowances	2,491	1
Net deferred tax liabilities	34,554	31

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

Balance sheet classification	**2013**	**20**
	(millions of dollars)	
Other current assets	(3,575)	(3
Other assets, including intangibles, net	(2,822)	(3
Accounts payable and accrued liabilities	421	
Deferred income tax liabilities	40,530	37
Net deferred tax liabilities	34,554	31

The Corporation had $47 billion of indefinitely reinvested, undistributed earnings from subsidiary companies outside the U.S. Unrecog deferred taxes on remittance of these funds are not expected to be material.

Unrecognized Tax Benefits. The Corporation is subject to income taxation in many jurisdictions around the world. Unrecognized tax be reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the fin statements. Resolution of the related tax positions through negotiations with the relevant tax authorities or through litigation will take years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control Corporation. It is reasonably possible that the total amount of unrecognized tax benefits could increase by up to 20 percent in the ne months, with no material impact on near-term earnings. Given the long time periods involved in resolving tax positions, the Corporation not expect that the recognition of unrecognized tax benefits will have a material impact on the Corporation's effective income tax rate i given year.

The following table summarizes the movement in unrecognized tax benefits.

Gross unrecognized tax benefits	**2013**	**2012**	**20**
		(millions of dollars)	
Balance at January 1	7,663	4,922	4
Additions based on current year's tax positions	1,460	1,662	
Additions for prior years' tax positions	464	2,559	
Reductions for prior years' tax positions	(249)	(535)	
Reductions due to lapse of the statute of limitations	(588)	(79)	
Settlements with tax authorities	(849)	(855)	
Foreign exchange effects/other	(63)	(11)	
Balance at December 31	7,838	7,663	4

The additions and reductions in unrecognized tax benefits shown above include effects related to net income and equity, and timing differ for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. The 2013, and 2011 changes in unrecognized tax benefits did not have a material effect on the Corporation's net income or cash flow.

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

Country of Operation	**Open Tax Years**
Abu Dhabi	2006 - 2013
Angola	2009 - 2013
Australia:	2000 - 2003
	2005
	2008 - 2013
Canada	2006 - 2013
Equatorial Guinea	2007 - 2013
Malaysia	2007 - 2013
Nigeria	1998 - 2013
Norway	2000 - 2013
Qatar	2007 - 2013
Russia	2010 - 2013
United Kingdom	2010 - 2013
United States	2006 - 2013

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

For 2013, the Corporation's net interest expense was a credit of $207 million, reflecting the effect of credits from the favorable resoluti prior year tax positions. The Corporation incurred $46 million and $62 million in interest expense on income tax reserves in 2012 and respectively. The related interest payable balances were $156 million and $385 million at December 31, 2013, and 2012, respectively.

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power opera technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for consolidated and equity companies totaled $886 million in 2013, $2,832 million in 2012, and $2,600 million in 2011. Oil sands m operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accou Standards Board rules.

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	T
				(millions of dollars)			
Consolidated Subsidiaries							
2013 - Revenue							
Sales to third parties	8,371	2,252	5,649	3,079	5,427	730	2
Transfers	6,505	5,666	5,654	15,738	8,936	1,405	4
	14,876	7,918	11,303	18,817	14,363	2,135	6
Production costs excluding taxes	4,191	3,965	2,859	2,396	1,763	654	1
Exploration expenses	394	386	245	288	571	92	
Depreciation and depletion	4,926	989	1,881	3,269	1,680	334	1
Taxes other than income	1,566	94	474	1,583	1,794	427	
Related income tax	1,788	542	4,124	6,841	5,709	202	1
Results of producing activities for consolidated subsidiaries	2,011	1,942	1,720	4,440	2,846	426	1
Equity Companies							
2013 - Revenue							
Sales to third parties	1,320	-	6,768	-	21,463	-	2
Transfers	1,034	-	64	-	6,091	-	
	2,354	-	6,832	-	27,554	-	3
Production costs excluding taxes	551	-	459	-	660	-	
Exploration expenses	19	-	15	-	426	-	
Depreciation and depletion	207	-	169	-	955	-	
Taxes other than income	51	-	3,992	-	7,352	-	1
Related income tax	-	-	832	-	8,482	-	
Results of producing activities for equity companies	1,526	-	1,365	-	9,679	-	1
Total results of operations	3,537	1,942	3,085	4,440	12,525	426	2

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	T
				(millions of dollars)			
Consolidated Subsidiaries							
2012 - Revenue							
Sales to third parties	6,977	1,804	5,835	3,672	6,536	1,275	2
Transfers	6,996	5,457	6,366	16,905	9,241	932	4
	13,973	7,261	12,201	20,577	15,777	2,207	7
Production costs excluding taxes	4,044	3,079	2,443	2,395	1,606	488	1
Exploration expenses	391	292	274	234	513	136	
Depreciation and depletion	4,862	848	1,559	2,879	1,785	264	1
Taxes other than income	1,963	89	513	1,702	2,248	446	
Related income tax	1,561	720	5,413	8,091	6,616	281	2
Results of producing activities for consolidated subsidiaries	1,152	2,233	1,999	5,276	3,009	592	1
Equity Companies							
2012 - Revenue							
Sales to third parties	1,284	-	6,380	-	20,017	-	2
Transfers	1,108	-	67	-	5,693	-	
	2,392	-	6,447	-	25,710	-	3
Production costs excluding taxes	467	-	369	-	484	-	
Exploration expenses	9	-	17	-	-	-	
Depreciation and depletion	176	-	152	-	676	-	
Taxes other than income	42	-	3,569	-	6,658	-	1
Related income tax	-	-	894	-	8,234	-	
Results of producing activities for equity companies	1,698	-	1,446	-	9,658	-	1
Total results of operations	2,850	2,233	3,445	5,276	12,667	592	2
Consolidated Subsidiaries							
2011 - Revenue							
Sales to third parties	8,579	1,056	8,050	3,507	6,813	1,061	2
Transfers	8,190	7,022	7,694	16,704	9,388	1,213	5
	16,769	8,078	15,744	20,211	16,201	2,274	7
Production costs excluding taxes	4,107	2,751	2,722	2,608	1,672	497	1
Exploration expenses	268	290	599	233	618	73	
Depreciation and depletion	4,664	980	1,928	2,159	1,680	236	1
Taxes other than income	2,157	79	631	2,055	2,164	295	
Related income tax	2,445	969	6,842	7,888	6,026	353	2
Results of producing activities for consolidated subsidiaries	3,128	3,009	3,022	5,268	4,041	820	1
Equity Companies							
2011 - Revenue							
Sales to third parties	1,356	-	5,580	-	18,855	-	2
Transfers	1,163	-	103	-	5,666	-	
	2,519	-	5,683	-	24,521	-	3
Production costs excluding taxes	482	-	315	-	378	-	
Exploration expenses	10	-	13	-	-	-	
Depreciation and depletion	151	-	160	-	576	-	
Taxes other than income	36	-	2,995	-	6,173	-	
Related income tax	-	-	847	-	8,036	-	
Results of producing activities for equity companies	1,840	-	1,353	-	9,358	-	1
Total results of operations	4,968	3,009	4,375	5,268	13,399	820	3

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $13,667 million less at year-end 2013 and $10,643 million l year-end 2012 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due t exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs		United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	T
					(millions of dollars)			
Consolidated Subsidiaries								
As of December 31, 2013								
Property (acreage) costs	- Proved	13,881	3,595	188	874	1,620	863	2
	- Unproved	23,945	5,390	61	583	701	146	3
Total property costs		37,826	8,985	249	1,457	2,321	1,009	5
Producing assets		74,743	34,487	44,161	40,424	30,082	7,973	23
Incomplete construction		5,640	11,811	2,219	5,913	8,387	4,194	3
Total capitalized costs		118,209	55,283	46,629	47,794	40,790	13,176	32
Accumulated depreciation and depletion		39,505	16,827	35,108	24,570	17,455	4,529	13
Net capitalized costs for consolidated subsidiaries		78,704	38,456	11,521	23,224	23,335	8,647	18
Equity Companies								
As of December 31, 2013								
Property (acreage) costs	- Proved	77	-	5	-	-	-	
	- Unproved	40	-	-	-	17	-	
Total property costs		117	-	5	-	17	-	
Producing assets		5,206	-	6,039	-	8,397	-	1
Incomplete construction		416	-	201	-	1,452	-	
Total capitalized costs		5,739	-	6,245	-	9,866	-	2
Accumulated depreciation and depletion		1,646	-	4,778	-	4,706	-	1
Net capitalized costs for equity companies		4,093	-	1,467	-	5,160	-	1
Consolidated Subsidiaries								
As of December 31, 2012								
Property (acreage) costs	- Proved	12,081	3,911	198	874	1,610	971	1
	- Unproved	25,769	1,456	89	430	710	162	2
Total property costs		37,850	5,367	287	1,304	2,320	1,133	4
Producing assets		70,603	21,947	44,068	37,921	23,230	6,910	20
Incomplete construction		4,840	18,726	1,589	5,070	12,654	5,988	4
Total capitalized costs		113,293	46,040	45,944	44,295	38,204	14,031	30
Accumulated depreciation and depletion		36,346	17,357	34,267	21,285	16,599	4,801	13
Net capitalized costs for consolidated subsidiaries		76,947	28,683	11,677	23,010	21,605	9,230	17
Equity Companies								
As of December 31, 2012								
Property (acreage) costs	- Proved	76	-	5	-	-	-	
	- Unproved	39	-	-	-	-	-	
Total property costs		115	-	5	-	-	-	
Producing assets		4,216	-	5,736	-	8,169	-	1
Incomplete construction		304	-	118	-	822	-	
Total capitalized costs		4,635	-	5,859	-	8,991	-	1
Accumulated depreciation and depletion		1,447	-	4,494	-	3,744	-	
Net capitalized costs for equity companies		3,188	-	1,365	-	5,247	-	

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also in new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation res from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2013 were $33,623 million, up $2,477 million 2012, due primarily to higher property acquisition costs partially offset by lower exploration costs. 2012 costs were $31,146 million, up million from 2011, due primarily to higher exploration and development costs partially offset by lower property acquisition costs. Total e company costs incurred in 2013 were $2,342 million, up $938 million from 2012, due primarily to higher exploration and development co

Costs Incurred in Property Acquisitions, Exploration and Development Activities	**United States**	**Canada/ South America**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**T**
				(millions of dollars)			
During 2013							
Consolidated Subsidiaries							
Property acquisition costs - Proved	93	67	-	-	47	-	
- Unproved	533	4,270	-	153	-	4	
Exploration costs	557	485	277	361	598	111	
Development costs	6,919	8,527	2,117	3,278	3,493	1,733	2
Total costs incurred for consolidated subsidiaries	8,102	13,349	2,394	3,792	4,138	1,848	3
Equity Companies							
Property acquisition costs - Proved	2	-	-	-	-	-	
- Unproved	-	-	-	-	17	-	
Exploration costs	60	-	29	-	494	-	
Development costs	720	-	192	-	828	-	
Total costs incurred for equity companies	782	-	221	-	1,339	-	
During 2012							
Consolidated Subsidiaries							
Property acquisition costs - Proved	192	2	95	-	43	-	
- Unproved	1,717	74	24	15	-	31	
Exploration costs	601	405	454	520	554	248	
Development costs	7,172	7,601	2,637	3,081	3,347	2,333	2
Total costs incurred for consolidated subsidiaries	9,682	8,082	3,210	3,616	3,944	2,612	3
Equity Companies							
Property acquisition costs - Proved	-	-	-	-	-	-	
- Unproved	14	-	-	-	-	-	
Exploration costs	45	-	34	-	-	-	
Development costs	504	-	156	-	651	-	
Total costs incurred for equity companies	563	-	190	-	651	-	
During 2011							
Consolidated Subsidiaries							
Property acquisition costs - Proved	259	-	-	-	96	-	
- Unproved	2,685	178	-	-	546	-	
Exploration costs	465	372	640	303	518	154	
Development costs	8,166	5,478	1,899	4,316	2,969	1,710	2
Total costs incurred for consolidated subsidiaries	11,575	6,028	2,539	4,619	4,129	1,864	3
Equity Companies							
Property acquisition costs - Proved	-	-	-	-	-	-	
- Unproved	23	-	-	-	-	-	
Exploration costs	19	-	32	-	-	-	
Development costs	339	-	164	-	649	-	
Total costs incurred for equity companies	381	-	196	-	649	-	

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2011, 2012, and 201

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

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

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

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due t evaluation or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production da (3) changes in average prices and year-end costs that are used in the estimation of reserves. This category can also include significant ch in either development strategy or production equipment/facility capacity.

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

In the proved reserves tables, consolidated reserves and equity company reserves are reported separately. However, the Corporation do view equity company reserves any differently than those from consolidated companies.

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined b specific fiscal terms in the agreement. The production and reserves that we report for these types of arrangements typically vary inversely oil and gas price changes. As oil and gas prices increase, the cash flow and value received by the company increase; however, the produ volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the op effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity compani year-end 2013 that were associated with production sharing contract arrangements was 11 percent of liquids, 9 percent of natural gas a percent on an oil-equivalent basis (gas converted to oil-equivalent at 6 billion cubic feet = 1 million barrels).

Net proved developed reserves are those volumes that are expected to be recovered through existing wells with existing equipmen operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Net p undeveloped reserves are those volumes that are expected to be recovered from new wells on undrilled acreage, or from existing wells wl relatively major expenditure is required for recompletion.

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

The changes between 2012 year-end proved reserves and 2013 year-end proved reserves reflect the extensions and discoveries in the U States and the Middle East.

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

	Crude Oil							Natural Gas Liquids *(1)*	Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ S. Amer.	Canada/ S. Amer.	T
							(millions of barrels)				
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2011	1,679	138	350	1,589	1,839	178	5,773	862	2,102	681	
Revisions	29	10	68	52	(55)	5	109	106	53	(4)	
Improved recovery	-	-	-	-	-	-	-	-	-	-	
Purchases	2	-	-	-	-	-	2	14	-	-	
Sales	(3)	(11)	(24)	-	-	-	(38)	(14)	-	-	
Extensions/discoveries	55	-	3	1	57	-	116	18	995	-	
Production	(102)	(19)	(80)	(179)	(120)	(13)	(513)	(81)	(44)	(24)	
December 31, 2011	1,660	118	317	1,463	1,721	170	5,449	905	3,106	653	1
Proportional interest in proved reserves of equity companies											
January 1, 2011	350	-	31	-	1,394	-	1,775	480	-	-	
Revisions	24	-	-	-	(21)	-	3	3	-	-	
Improved recovery	-	-	-	-	-	-	-	-	-	-	
Purchases	-	-	-	-	-	-	-	-	-	-	
Sales	(2)	-	-	-	-	-	(2)	-	-	-	
Extensions/discoveries	-	-	-	-	12	-	12	25	-	-	
Production	(24)	-	(2)	-	(130)	-	(156)	(25)	-	-	
December 31, 2011	348	-	29	-	1,255	-	1,632	483	-	-	
Total liquids proved reserves at December 31, 2011	2,008	118	346	1,463	2,976	170	7,081	1,388	3,106	653	1
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2012	1,660	118	317	1,463	1,721	170	5,449	905	3,106	653	1
Revisions	25	33	14	20	(10)	5	87	3	265	(29)	
Improved recovery	6	-	-	-	1	-	7	-	-	-	
Purchases	163	-	20	-	-	-	183	36	-	-	
Sales	(15)	(1)	(8)	(58)	-	-	(82)	(4)	-	-	
Extensions/discoveries	166	138	8	41	9	-	362	164	234	-	
Production	(100)	(18)	(62)	(173)	(117)	(12)	(482)	(73)	(45)	(25)	
December 31, 2012	1,905	270	289	1,293	1,604	163	5,524	1,031	3,560	599	1
Proportional interest in proved reserves of equity companies											
January 1, 2012	348	-	29	-	1,255	-	1,632	483	-	-	
Revisions	(2)	-	1	-	131	-	130	15	-	-	
Improved recovery	16	-	-	-	-	-	16	-	-	-	
Purchases	-	-	-	-	-	-	-	-	-	-	
Sales	-	-	-	-	-	-	-	-	-	-	
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	
Production	(22)	-	(2)	-	(126)	-	(150)	(24)	-	-	
December 31, 2012	340	-	28	-	1,260	-	1,628	474	-	-	
Total liquids proved reserves at December 31, 2012	2,245	270	317	1,293	2,864	163	7,152	1,505	3,560	599	1

(See footnote on next page)

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

	Crude Oil							Natural Gas Liquids *(1)*	Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ S. Amer.	Canada/ S. Amer.	T
							(millions of barrels)				
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2013	1,905	270	289	1,293	1,604	163	5,524	1,031	3,560	599	1
Revisions	21	20	13	13	411	3	481	(1)	124	4	
Improved recovery	-	-	-	-	-	-	-	-	-	-	
Purchases	15	15	-	-	-	-	30	27	-	-	
Sales	(18)	-	-	-	-	-	(18)	(6)	-	-	
Extensions/discoveries	188	-	-	52	262	-	502	39	-	-	
Production	(103)	(21)	(57)	(165)	(114)	(11)	(471)	(67)	(54)	(24)	
December 31, 2013	2,008	284	245	1,193	2,163	155	6,048	1,023	3,630	579	1
Proportional interest in proved reserves of equity companies											
January 1, 2013	340	-	28	-	1,260	-	1,628	474	-	-	
Revisions	12	-	2	-	21	-	35	8	-	-	
Improved recovery	-	-	-	-	-	-	-	-	-	-	
Purchases	-	-	-	-	-	-	-	-	-	-	
Sales	-	-	-	-	-	-	-	-	-	-	
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	
Production	(22)	-	(2)	-	(136)	-	(160)	(26)	-	-	
December 31, 2013	330	-	28	-	1,145	-	1,503	456	-	-	
Total liquids proved reserves at December 31, 2013	2,338	284	273	1,193	3,308	155	7,551	1,479	3,630	579	1

(1) Includes total proved reserves attributable to Imperial Oil Limited of 10 million barrels in 2011, 9 million barrels in 2012 and 11 million barrels in as well as proved developed reserves of 10 million barrels in 2011, 9 million barrels in 2012 and 9 million barrels in 2013, and in addition, undeveloped reserves of 2 million barrels in 2013, in which there is a 30.4 percent noncontrolling interest.

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ South Amer. *(2)*	Canada/ South Amer. *(3)*	T
					(millions of barrels)					
Proved developed reserves, as of December 31, 2011										
Consolidated subsidiaries	1,452	109	302	1,050	1,160	126	4,199	519	653	
Equity companies	270	-	28	-	1,457	-	1,755	-	-	
Proved undeveloped reserves, as of December 31, 2011										
Consolidated subsidiaries	567	26	74	625	727	136	2,155	2,587	-	
Equity companies	83	-	1	-	276	-	360	-	-	
Total liquids proved reserves at December 31, 2011	2,372	135	405	1,675	3,620	262	8,469	3,106	653	1
Proved developed reserves, as of December 31, 2012										
Consolidated subsidiaries	1,489	124	268	1,004	1,080	116	4,081	543	599	
Equity companies	264	-	28	-	1,423	-	1,715	-	-	
Proved undeveloped reserves, as of December 31, 2012										
Consolidated subsidiaries	921	163	77	497	682	134	2,474	3,017	-	
Equity companies	84	-	-	-	303	-	387	-	-	
Total liquids proved reserves at December 31, 2012	2,758	287	373	1,501	3,488	250	8,657	3,560	599	1
Proved developed reserves, as of December 31, 2013										
Consolidated subsidiaries	1,469	126	249	945	1,663	105	4,557	1,810	579	
Equity companies	268	-	27	-	1,292	-	1,587	-	-	
Proved undeveloped reserves, as of December 31, 2013										
Consolidated subsidiaries	1,068	177	51	449	638	131	2,514	1,820	-	
Equity companies	77	-	1	-	294	-	372	-	-	
Total liquids proved reserves at December 31, 2013	2,882	303	328	1,394	3,887	236	9,030 *(4)*	3,630	579	1

(1) Includes total proved reserves attributable to Imperial Oil Limited of 55 million barrels in 2011, 53 million barrels in 2012 and 62 million barrels in as well as proved developed reserves of 55 million barrels in 2011, 52 million barrels in 2012 and 55 million barrels in 2013, and in addition, p undeveloped reserves of 1 million barrels in 2012 and 7 million barrels in 2013, in which there is a 30.4 percent noncontrolling interest.

(2) Includes total proved reserves attributable to Imperial Oil Limited of 2,413 million barrels in 2011, 2,841 million barrels in 2012 and 2,867 n barrels in 2013, as well as proved developed reserves of 519 million barrels in 2011, 543 million barrels in 2012 and 1,417 million barrels in 2013, addition, proved undeveloped reserves of 1,894 million barrels in 2011, 2,298 million barrels in 2012 and 1,450 million barrels in 2013, in which tl a 30.4 percent noncontrolling interest.

(3) Includes total proved reserves attributable to Imperial Oil Limited of 653 million barrels in 2011, 599 million barrels in 2012 and 579 million bar 2013, as well as proved developed reserves of 653 million barrels in 2011, 599 million barrels in 2012 and 579 million barrels in 2013, in which the 30.4 percent noncontrolling interest.

(4) See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional informat natural gas liquids proved reserves see Item 2. Properties in ExxonMobil's 2013 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivale Total All Products (**
	(billions of cubic feet)							*(millions of o equivalent b*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2011	25,994	1,258	4,042	908	7,260	7,351	46,813	17,220
Revisions	(236)	55	310	113	(231)	28	39	271
Improved recovery	-	-	-	-	-	-	-	-
Purchases	303	-	-	-	-	-	303	67
Sales	(32)	(347)	(140)	-	-	-	(519)	(138)
Extensions/discoveries	1,779	42	29	-	192	-	2,042	1,469
Production	(1,554)	(173)	(655)	(39)	(750)	(132)	(3,303)	(1,213)
December 31, 2011	26,254	835	3,586	982	6,471	7,247	45,375	17,676
Proportional interest in proved reserves of equity companies								
January 1, 2011	117	-	10,746	-	21,139	-	32,002	7,589
Revisions	1	-	53	-	(29)	-	25	10
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	(1)	-	(3)	-	-	-	(4)	(3)
Extensions/discoveries	-	-	13	-	627	-	640	144
Production	(5)	-	(640)	-	(1,171)	-	(1,816)	(484)
December 31, 2011	112	-	10,169	-	20,566	-	30,847	7,256
Total proved reserves at December 31, 2011	26,366	835	13,755	982	27,037	7,247	76,222	24,932
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2012	26,254	835	3,586	982	6,471	7,247	45,375	17,676
Revisions	(2,888)	168	168	2	(106)	465	(2,191)	(39)
Improved recovery	-	-	-	-	-	-	-	7
Purchases	503	-	6	-	-	-	509	304
Sales	(181)	(20)	(140)	(12)	-	-	(353)	(145)
Extensions/discoveries	4,045	95	184	-	59	-	4,383	1,490
Production	(1,518)	(153)	(555)	(43)	(579)	(144)	(2,992)	(1,124)
December 31, 2012	26,215	925	3,249	929	5,845	7,568	44,731	18,169
Proportional interest in proved reserves of equity companies								
January 1, 2012	112	-	10,169	-	20,566	-	30,847	7,256
Revisions	49	-	17	-	252	-	318	198
Improved recovery	-	-	-	-	-	-	-	16
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-
Production	(6)	-	(651)	-	(1,148)	-	(1,805)	(475)
December 31, 2012	155	-	9,535	-	19,670	-	29,360	6,995
Total proved reserves at December 31, 2012	26,370	925	12,784	929	25,515	7,568	74,091	25,164

(See footnotes on next page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivale Total All Products (**
	(billions of cubic feet)							*(millions of o equivalent b*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2013	26,215	925	3,249	929	5,845	7,568	44,731	18,169
Revisions	79	(56)	61	(22)	364	86	512	693
Improved recovery	-	-	-	-	-	-	-	-
Purchases	153	522	-	-	-	-	675	170
Sales	(106)	(8)	-	-	-	-	(114)	(43)
Extensions/discoveries	1,083	2	-	-	14	-	1,099	724
Production	(1,404)	(150)	(500)	(40)	(489)	(139)	(2,722)	(1,069)
December 31, 2013	26,020	1,235	2,810	867	5,734	7,515	44,181	18,644
Proportional interest in proved reserves of equity companies								
January 1, 2013	155	-	9,535	-	19,670	-	29,360	6,995
Revisions	135	-	58	-	9	-	202	77
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	8	-	-	-	9	2
Production	(10)	-	(717)	-	(1,165)	-	(1,892)	(502)
December 31, 2013	281	-	8,884	-	18,514	-	27,679	6,572
Total proved reserves at December 31, 2013	26,301	1,235	11,694	867	24,248	7,515	71,860	25,216

(1) Includes total proved reserves attributable to Imperial Oil Limited of 422 billion cubic feet in 2011, 488 billion cubic feet in 2012 an billion cubic feet in 2013, as well as proved developed reserves of 360 billion cubic feet in 2011, 374 billion cubic feet in 2012 an billion cubic feet in 2013, and in addition, proved undeveloped reserves of 62 billion cubic feet in 2011, 114 billion cubic feet in 201 310 billion cubic feet in 2013, in which there is a 30.4 percent noncontrolling interest.

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivale Total All Products (**
	(billions of cubic feet)							*(millions of o equivalent b*
Proved developed reserves, as of December 31, 2011								
Consolidated subsidiaries	15,450	658	3,041	853	5,762	1,070	26,834	9,843
Equity companies	83	-	7,588	-	19,305	-	26,976	6,251
Proved undeveloped reserves, as of December 31, 2011								
Consolidated subsidiaries	10,804	177	545	129	709	6,177	18,541	7,833
Equity companies	29	-	2,581	-	1,261	-	3,871	1,005
Total proved reserves at December 31, 2011	26,366	835	13,755	982	27,037	7,247	76,222	24,932
Proved developed reserves, as of December 31, 2012								
Consolidated subsidiaries	14,471	670	2,526	814	5,150	1,012	24,643	9,330
Equity companies	126	-	7,057	-	18,431	-	25,614	5,984
Proved undeveloped reserves, as of December 31, 2012								
Consolidated subsidiaries	11,744	255	723	115	695	6,556	20,088	8,839
Equity companies	29	-	2,478	-	1,239	-	3,746	1,011
Total proved reserves at December 31, 2012	26,370	925	12,784	929	25,515	7,568	74,091	25,164
Proved developed reserves, as of December 31, 2013								
Consolidated subsidiaries	14,655	664	2,189	779	5,241	969	24,497	11,029
Equity companies	197	-	6,852	-	17,288	-	24,337	5,643
Proved undeveloped reserves, as of December 31, 2013								
Consolidated subsidiaries	11,365	571	621	88	493	6,546	19,684	7,615
Equity companies	84	-	2,032	-	1,226	-	3,342	929
Total proved reserves at December 31, 2013	26,301	1,235	11,694	867	24,248	7,515	71,860	25,216

(See footnotes on previous page)

Standardized Measure of Discounted Future Cash Flows

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

Standardized Measure of Discounted Future Cash Flows	United States	Canada/ South America *(1)*	Europe	Africa	Asia	Australia/ Oceania	To
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2011							
Future cash inflows from sales of oil and gas	264,991	280,991	71,847	179,337	203,007	86,456	1,08
Future production costs	105,391	98,135	15,045	36,309	43,442	23,381	32
Future development costs	31,452	35,121	11,987	15,384	16,010	10,052	12
Future income tax expenses	53,507	34,542	32,004	67,256	79,975	17,287	28
Future net cash flows	74,641	113,193	12,811	60,388	63,580	35,736	36
Effect of discounting net cash flows at 10%	42,309	79,303	3,525	22,029	38,066	22,873	20
Discounted future net cash flows	32,332	33,890	9,286	38,359	25,514	12,863	15
Equity Companies							
As of December 31, 2011							
Future cash inflows from sales of oil and gas	37,398	-	88,417	-	324,283	-	45
Future production costs	6,862	-	62,377	-	104,040	-	17
Future development costs	3,072	-	2,701	-	3,636	-	
Future income tax expenses	-	-	9,035	-	76,825	-	8
Future net cash flows	27,464	-	14,304	-	139,782	-	18
Effect of discounting net cash flows at 10%	15,941	-	7,131	-	71,918	-	9
Discounted future net cash flows	11,523	-	7,173	-	67,864	-	8
Total consolidated and equity interests in standardized measure of discounted future net cash flows	43,855	33,890	16,459	38,359	93,378	12,863	23

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $27,568 million in 2011, in which there is a 30.4 pe noncontrolling interest.

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ South America *(1)*	Europe	Africa	Asia	Australia/ Oceania	To
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	250,382	293,910	66,769	160,261	192,491	104,334	1,068
Future production costs	109,325	101,299	17,277	33,398	42,816	26,132	330
Future development costs	37,504	44,518	16,505	13,363	13,083	11,435	136
Future income tax expenses	43,772	34,692	23,252	63,246	75,261	21,405	261
Future net cash flows	59,781	113,401	9,735	50,254	61,331	45,362	339
Effect of discounting net cash flows at 10%	36,578	82,629	2,097	18,091	35,310	27,610	202
Discounted future net cash flows	23,203	30,772	7,638	32,163	26,021	17,752	137
Equity Companies							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	36,043	-	93,563	-	348,026	-	477
Future production costs	7,040	-	64,988	-	112,980	-	185
Future development costs	3,708	-	2,569	-	10,780	-	17
Future income tax expenses	-	-	9,937	-	78,539	-	88
Future net cash flows	25,295	-	16,069	-	145,727	-	187
Effect of discounting net cash flows at 10%	14,741	-	8,133	-	76,979	-	99
Discounted future net cash flows	10,554	-	7,936	-	68,748	-	87
Total consolidated and equity interests in standardized measure of discounted future net cash flows	33,757	30,772	15,574	32,163	94,769	17,752	224
Consolidated Subsidiaries							
As of December 31, 2013							
Future cash inflows from sales of oil and gas	276,051	293,377	58,235	146,407	245,482	87,808	1,107
Future production costs	113,571	106,884	18,053	30,960	57,328	22,507	349
Future development costs	40,702	43,102	15,215	14,300	10,666	10,191	134
Future income tax expenses	50,144	31,901	17,186	53,766	117,989	16,953	287
Future net cash flows	71,634	111,490	7,781	47,381	59,499	38,157	335
Effect of discounting net cash flows at 10%	42,336	78,700	1,278	18,406	34,878	21,266	196
Discounted future net cash flows	29,298	32,790	6,503	28,975	24,621	16,891	139
Equity Companies							
As of December 31, 2013							
Future cash inflows from sales of oil and gas	34,957	-	82,539	-	324,666	-	442
Future production costs	8,231	-	60,518	-	107,656	-	176
Future development costs	3,675	-	2,994	-	8,756	-	15
Future income tax expenses	-	-	7,237	-	70,887	-	78
Future net cash flows	23,051	-	11,790	-	137,367	-	172
Effect of discounting net cash flows at 10%	12,994	-	5,549	-	72,798	-	91
Discounted future net cash flows	10,057	-	6,241	-	64,569	-	80
Total consolidated and equity interests in standardized measure of discounted future net cash flows	39,355	32,790	12,744	28,975	89,190	16,891	219

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $24,690 million in 2012 and $25,160 million in 20 which there is a 30.4 percent noncontrolling interest.

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

Consolidated and Equity Interests		**2011**	
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolida and Equi Interest**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2010	114,238	61,284	175,52
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	6,608	309	6,91
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(58,308)	(22,402)	(80,71
Development costs incurred during the year	22,843	1,153	23,99
Net change in prices, lifting and development costs	79,435	46,304	125,73
Revisions of previous reserves estimates	10,462	3,127	13,58
Accretion of discount	16,802	7,196	23,99
Net change in income taxes	(39,836)	(10,411)	(50,24
Total change in the standardized measure during the year	38,006	25,276	63,28
Discounted future net cash flows as of December 31, 2011	152,244	86,560	238,80

Consolidated and Equity Interests		**2012**	
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolida and Equi Interest**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2011	152,244	86,560	238,80
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	7,952	531	8,48
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(51,752)	(23,022)	(74,77
Development costs incurred during the year	24,596	1,186	25,78
Net change in prices, lifting and development costs	(31,382)	5,656	(25,72
Revisions of previous reserves estimates	3,876	7,018	10,89
Accretion of discount	19,676	8,846	28,52
Net change in income taxes	12,339	463	12,80
Total change in the standardized measure during the year	(14,695)	678	(14,01
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,78

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

Consolidated and Equity Interests (continued)	2013		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolida and Equi Interest
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,787
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	11,928	48	11,976
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(48,742)	(23,757)	(72,499
Development costs incurred during the year	24,821	1,389	26,210
Net change in prices, lifting and development costs	(32,423)	(5,296)	(37,719
Revisions of previous reserves estimates	24,353	4,960	29,313
Accretion of discount	20,596	9,830	30,426
Net change in income taxes	996	6,455	7,451
Total change in the standardized measure during the year	1,529	(6,371)	(4,842
Discounted future net cash flows as of December 31, 2013	139,078	80,867	219,945

OPERATING SUMMARY (unaudited)

	2013	2012	2011	2010
Production of crude oil, natural gas liquids, bitumen and synthetic oil				
Net production			*(thousands of barrels daily)*	
United States	431	418	423	408
Canada/South America	280	251	252	263
Europe	190	207	270	335
Africa	469	487	508	628
Asia	784	772	808	730
Australia/Oceania	48	50	51	58
Worldwide	2,202	2,185	2,312	2,422
Natural gas production available for sale				
Net production			*(millions of cubic feet daily)*	
United States	3,545	3,822	3,917	2,596
Canada/South America	354	362	412	569
Europe	3,251	3,220	3,448	3,836
Africa	6	17	7	14
Asia	4,329	4,538	5,047	4,801
Australia/Oceania	351	363	331	332
Worldwide	11,836	12,322	13,162	12,148
			(thousands of oil-equivalent barrels daily)	
Oil-equivalent production *(1)*	4,175	4,239	4,506	4,447
Refinery throughput			*(thousands of barrels daily)*	
United States	1,819	1,816	1,784	1,753
Canada	426	435	430	444
Europe	1,400	1,504	1,528	1,538
Asia Pacific	779	998	1,180	1,249
Other Non-U.S.	161	261	292	269
Worldwide	4,585	5,014	5,214	5,253
Petroleum product sales *(2)*				
United States	2,609	2,569	2,530	2,511
Canada	464	453	455	450
Europe	1,497	1,571	1,596	1,611
Asia Pacific and other Eastern Hemisphere	1,206	1,381	1,556	1,562
Latin America	111	200	276	280
Worldwide	5,887	6,174	6,413	6,414
Gasoline, naphthas	2,418	2,489	2,541	2,611
Heating oils, kerosene, diesel oils	1,838	1,947	2,019	1,951
Aviation fuels	462	473	492	476
Heavy fuels	431	515	588	603
Specialty petroleum products	738	750	773	773
Worldwide	5,887	6,174	6,413	6,414
Chemical prime product sales *(3)*			*(thousands of metric tons)*	
United States	9,679	9,381	9,250	9,815
Non-U.S.	14,384	14,776	15,756	16,076
Worldwide	24,063	24,157	25,006	25,891

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

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

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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly causec report to be signed on its behalf by the undersigned, thereunto duly authorized.

EXXON MOBIL CORPORATION

By: /s/ REX W. TILLERSON
(Rex W. Tillerson,
Chairman of the Board)

Dated February 26, 2014

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Randall M. Ebner, Leonard M. Fox and Catherine C. and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for hi her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on l 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exch Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform eacl every act and thing requisite and necessary to be done, as fully to all intents and purposes as he or she might or could do in pe hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his or her substitu substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following perso behalf of the registrant and in the capacities indicated and on February 26, 2014.

/s/ REX W. TILLERSON (Rex W. Tillerson)	Chairman of the Board (Principal Executive Office
/s/ MICHAEL J. BOSKIN (Michael J. Boskin)	Director
/s/ PETER BRABECK-LETMATHE (Peter Brabeck-Letmathe)	Director
/s/ URSULA M. BURNS (Ursula M. Burns)	Director
/s/ LARRY R. FAULKNER (Larry R. Faulkner)	Director

/s/ JAY S. FISHMAN (Jay S. Fishman)	Director
/s/ HENRIETTA H. FORE (Henrietta H. Fore)	Director
/s/ KENNETH C. FRAZIER (Kenneth C. Frazier)	Director
/s/ WILLIAM W. GEORGE (William W. George)	Director
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director
/s/ STEVEN S REINEMUND (Steven S Reinemund)	Director
/s/ WILLIAM C. WELDON (William C. Weldon)	Director
/s/ EDWARD E. WHITACRE, JR. (Edward E. Whitacre, Jr.)	Director
/s/ ANDREW P. SWIGER (Andrew P. Swiger)	Senior Vice President (Principal Financial Office
/s/ PATRICK T. MULVA (Patrick T. Mulva)	Vice President and Control (Principal Accounting Offic

INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, (incorporated by reference to Exhibit 3(i) to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended Jur 2011).
3(ii)	By-Laws, as revised to April 27, 2011 (incorporated by reference to Exhibit 3(ii) to the Registrant’s Report on Form 8- April 29, 2011).
10(iii)(a.1)	2003 Incentive Program, as approved by shareholders May 28, 2003 (incorporated by reference to Exhibit 10(iii)(a.1) t Registrant’s Annual Report on Form 10-K for 2012).*
10(iii)(a.2)	Extended Provisions for Restricted Stock Agreements (incorporated by reference to Exhibit 99.2 to the Registrant’s Repo Form 8-K of November 28, 2012).*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements – Settlement in Shares.*
10(iii)(a.4)	Standard Provisions for Restricted Stock Unit Agreements – Settlement in Cash.*
10(iii)(b.1)	Short Term Incentive Program, as amended.*
10(iii)(b.2)	Earnings Bonus Unit instrument.*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan.*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan.*
10(iii)(c.3)	ExxonMobil Additional Payments Plan.*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Regist Annual Report on Form 10-K for 2011).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan.*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by referen Exhibit 10(iii)(f.2) to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors (incorporated by reference to Exhibit 10(iii)(f.3) t Registrant’s Annual Report on Form 10-K for 2009).*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated October 26, 2011 (incorporated by reference to Exhibit 10(iii to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011).*
10(iii)(g.3)	1984 Mobil Compensation Management Retention Plan (incorporated by reference to Exhibit 10(iii)(g.3) to the Regist Annual Report on Form 10-K for 2011).*
12	Computation of ratio of earnings to fixed charges.
14	Code of Ethics and Business Conduct.
21	Subsidiaries of the registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31.1	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.
31.2	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Financial Officer.
31.3	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting Officer.

Exhibit	Description
32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.
32.2	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Financial Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
101	Interactive data files.

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

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