2014

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

FORM 10-K

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

For the fiscal year ended December 31, 2014

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 (4,194,690,266 shares outstanding at January 31, 2015)	**New York Stock Exchange**

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

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer ☐
Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, base on the closing price on that date of $100.68 on the New York Stock Exchange composite tape, was in excess of $429 billion.

Documents Incorporated by Reference: Proxy Statement for the 2015 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2014

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PART I

ITEM 1. BUSINESS

Exxon Mobil Corporation was incorporated in the State of New Jersey in 1882. Divisions and affiliated companies of ExxonMobil operate or market products in the United States ar most other countries of the world. Their principal business is energy, involving exploration for, and production of, crude oil and natural gas, manufacture of petroleum products an transportation and sale of crude oil, natural gas and petroleum products. ExxonMobil is a major manufacturer and marketer of commodity petrochemicals, including olefins, aromatic polyethylene and polypropylene plastics and a wide variety of specialty products. Affiliates of ExxonMobil conduct extensive research programs in support of these businesses.

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

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significar investment in refining infrastructure and technology to manufacture clean fuels, as well as projects to monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions, ar expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2014 worldwide environmental expenditur for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $6.2 billion, of which $3.5 billion were included in expenses with th remainder in capital expenditures. The total cost for such activities is expected to remain in this range in 2015 and 2016 (with capital expenditures approximately 40 percent of the total).

The energy and petrochemical industries are highly competitive. There is competition within the industries and also with other industries in supplying the energy, fuel and chemic needs of both industrial and individual consumers. The Corporation competes with other firms in the sale or purchase of needed goods and services in many national and internation markets and employs all methods of competition which are lawful and appropriate for such purposes.

Operating data and industry segment information for the Corporation are contained in the Financial Section of this report under the following: "Quarterly Information", "Note 1 Disclosures about Segments and Related Information" and "Operating Summary". Information on oil and gas reserves is contained in the "Oil and Gas Reserves" part of th "Supplemental Information on Oil and Gas Exploration and Production Activities" portion of the Financial Section of this report.

ExxonMobil has a long-standing commitment to the development of proprietary technology. We have a wide array of research programs designed to meet the needs identified in eac of our business segments. Information on Company-sponsored research and development spending is contained in "Note 3: Miscellaneous Financial Information" of the Financial Sectic of this report. ExxonMobil held approximately 11 thousand active patents worldwide at the end of 2014. For technology licensed to third parties, revenues totaled approximate $148 million in 2014. Although technology is an important contributor to the overall operations and results of our Company, the profitability of each business segment is not dependent o any individual patent, trade secret, trademark, license, franchise or concession.

The number of regular employees was 75.3 thousand, 75.0 thousand, and 76.9 thousand at years ended 2014, 2013 and 2012, respectively. Regular employees are defined as activ executive, management, professional, technical and wage employees who work full time or part time for the Corporation and are covered by the Corporation's benefit plans and program Regular employees do not include employees of the company-operated retail sites (CORS). The number of CORS employees was 8.4 thousand, 9.8 thousand, and 11.1 thousand at yea ended 2014, 2013 and 2012, respectively.

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

ExxonMobil maintains a website at exxonmobil.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to thos reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available through our website as soon as reasonably practical after we electronicall file or furnish the reports to the Securities and Exchange Commission. Also available on the Corporation's website are the Company's Corporate Governance Guidelines and Code c Ethics and Business Conduct, as well as the charters of the audit, compensation and nominating committees of the Board of Directors. Information on our website is not incorporated in this report.

ITEM 1A. RISK FACTORS

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

Supply and Demand

The oil, gas, and petrochemical businesses are fundamentally commodity businesses. This means ExxonMobil's operations and earnings may be significantly affected by changes in oi gas and petrochemical prices and by changes in margins on refined products. Oil, gas, petrochemical and product prices and margins in turn depend on local, regional and global events conditions that affect supply and demand for the relevant commodity.

Economic conditions. The demand for energy and petrochemicals correlates closely with general economic growth rates. The occurrence of recessions or other periods of low or negati economic growth will typically have a direct adverse impact on our results. Other factors that affect general economic conditions in the world or in a major region, such as changes population growth rates, periods of civil unrest, government austerity programs, or currency exchange rate fluctuations, can also impact the demand for energy and petrochemical Sovereign debt downgrades, defaults, inability to access debt markets due to credit or legal constraints, liquidity crises, the breakup or restructuring of fiscal, monetary, or political systen such as the European Union, and other events or conditions that impair the functioning of financial markets and institutions also pose risks to ExxonMobil, including risks to the safety our financial assets and to the ability of our partners and customers to fulfill their commitments to ExxonMobil.

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

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

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

Government and Political Factors

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

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

Restrictions on doing business. ExxonMobil is subject to laws and sanctions imposed by the U.S. or by other jurisdictions where we do business that may prohibit ExxonMobil or certa of its affiliates from doing business in certain countries, or restricting the kind of business that may be conducted. Such restrictions may provide a competitive advantage to competito who may not be subject to comparable restrictions.

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

Regulatory and litigation risks. Even in countries with well-developed legal systems where ExxonMobil does business, we remain exposed to changes in law (including changes th result from international treaties and accords) that could adversely affect our results, such as:

- increases in taxes or government royalty rates (including retroactive claims);
- price controls;
- changes in environmental regulations or other laws that increase our cost of compliance or reduce or delay available business opportunities (including changes in laws relat to offshore drilling operations, water use, or hydraulic fracturing);
- adoption of regulations mandating the use of alternative fuels or uncompetitive fuel components;
- adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information, or that could cause us to viola the non-disclosure laws of other countries; and
- government actions to cancel contracts, re-denominate the official currency, renounce or default on obligations, renegotiate terms unilaterally, or expropriate assets.

Legal remedies available to compensate us for expropriation or other takings may be inadequate.

We also may be adversely affected by the outcome of litigation, especially in countries such as the United States in which very large and unpredictable punitive damage awards ma occur, or by government enforcement proceedings alleging non-compliance with applicable laws or regulations.

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

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

Government sponsorship of alternative energy. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use specific fuels or technologies. Governments are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. We a conducting our own research efforts into alternative energy, such as through sponsorship of the Global Climate and Energy Project at Stanford University and research into liquid produc from algae and biomass that can be further converted to transportation fuels. Our future results may depend in part on the success of our research efforts and on our ability to adapt a apply the strengths of our current business model to providing the energy products of the future in a cost-competitive manner. See “Management Effectiveness” below.

Management Effectiveness

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

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

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

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

Operational efficiency. An important component of ExxonMobil’s competitive performance, especially given the commodity-based nature of many of our businesses, is our ability t operate efficiently, including our ability to manage expenses and improve production yields on an ongoing basis. This requires continuous management focus, including technolog improvements, cost control, productivity enhancements, regular reappraisal of our asset portfolio, and the recruitment, development and retention of high caliber employees.

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

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

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

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

Projections, estimates and descriptions of ExxonMobil’s plans and objectives included or incorporated in Items 1, 1A, 2, 7 and 7A of this report are forward-looking statements. Actua future results, including project completion dates, production rates, capital expenditures, costs and business plans could differ materially due to, among other things, the factors discusse 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 2014

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and equity companies. The Corporation ha reported proved reserves on the basis of the average of the first-day-of-the-month price for each month during the last 12-month period. Gas is converted to an oil-equivalent basis at s million cubic feet per one thousand barrels. No major discovery or other favorable or adverse event has occurred since December 31, 2014, that would cause a significant change in th estimated proved reserves as of that date.

	Crude Oil	Natural Gas Liquids	Bitumen	Synthetic Oil	Natural Gas	Oil-Equivalent Basis
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million bbls)*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,215	287	-	-	14,169	3,864
Canada/South America *(1)*	98	13	2,122	534	615	2,869
Europe	170	35	-	-	1,870	517
Africa	722	172	-	-	764	1,021
Asia	1,481	134	-	-	5,031	2,453
Australia/Oceania	74	38	-	-	2,179	475
Total Consolidated	3,760	679	2,122	534	24,628	11,199
Equity Companies						
United States	259	10	-	-	194	301
Europe	26	-	-	-	6,484	1,107
Asia	822	366	-	-	16,305	3,906
Total Equity Company	1,107	376	-	-	22,983	5,314
Total Developed	4,867	1,055	2,122	534	47,611	16,513
Undeveloped						
Consolidated Subsidiaries						
United States	893	341	-	-	11,818	3,203
Canada/South America *(1)*	184	6	2,111	-	611	2,403
Europe	29	13	-	-	513	127
Africa	380	21	-	-	47	409
Asia	651	-	-	-	429	723
Australia/Oceania	67	32	-	-	5,097	949
Total Consolidated	2,204	413	2,111	-	18,515	7,814
Equity Companies						
United States	69	6	-	-	78	88
Europe	1	-	-	-	1,934	323
Asia	278	53	-	-	1,200	531
Total Equity Company	348	59	-	-	3,212	942
Total Undeveloped	2,552	472	2,111	-	21,727	8,756
Total Proved Reserves	7,419	1,527	4,233	534	69,338	25,269

(1) South America includes proved developed reserves of 0.2 million barrels of crude oil and natural gas liquids and 39 billion cubic feet of natural gas and proved undeveloped reser of 7 billion cubic feet of natural gas.

In the preceding reserves information, consolidated subsidiary and equity company reserves are reported separately. However, the Corporation operates its business with the same view c equity company reserves as it has for reserves from consolidated subsidiaries.

The Corporation's overall volume capacity outlook, based on projects coming on stream as anticipated, is for production capacity to grow over the coming years. However, actua volumes will vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, the impact of fiscal and commerci terms, asset sales, weather events, price effects on production sharing contracts and other factors as described in Item 1A—Risk Factors of this report.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and mark assessments and detailed analysis of well and reservoir information such as flow rates and reservoir pressure declines. Furthermore, the Corporation only records proved reserves f projects which have received significant funding commitments by management made toward the development of the reserves. Although the Corporation is reasonably certain that prove reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulato approvals and significant changes in projections of long-term oil and gas price levels.

B. Technologies Used in Establishing Proved Reserves Additions in 2014

Additions to ExxonMobil's proved reserves in 2014 were based on estimates generated through the integration of available and appropriate geological, engineering and production dat utilizing well-established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static ar dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indire measurements including high-quality 3-D and 4-D seismic data, calibrated with available well control information. The tools used to interpret the data included proprietary seism processing software, proprietary reservoir modeling and simulation software, and commercially available data analysis packages.

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

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

ExxonMobil has a dedicated Global Reserves group that provides technical oversight and is separate from the operating organization. Primary responsibilities of this group incluc oversight of the reserves estimation process for compliance with Securities and Exchange Commission (SEC) rules and regulations, review of annual changes in reserves estimates, and th reporting of ExxonMobil's proved reserves. This group also maintains the official company reserves estimates for ExxonMobil's proved reserves of crude and natural gas liquids, bitumen synthetic oil and natural gas. In addition, the group provides training to personnel involved in the reserves estimation and reporting process within ExxonMobil and its affiliates. Th Manager of the Global Reserves group has more than 30 years of experience in reservoir engineering and reserves assessment and has a degree in Engineering. He is an active member the Society of Petroleum Engineers (SPE) and previously served on the SPE Oil and Gas Reserves Committee. The group is managed by and staffed with individuals that have an averag of more than 20 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves under the SEC guidelines. This grou includes individuals who hold advanced degrees in either Engineering or Geology. Several members of the group hold professional registrations in their field of expertise, and membe have served on the SPE Oil and Gas Reserves Committee.

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

2. Proved Undeveloped Reserves

At year-end 2014, approximately 8.8 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 35 percent of the 25. GOEB reported in proved reserves. This compares to the 8.5 GOEB of proved undeveloped reserves reported at the end of 2013. During the year, ExxonMobil conducted developmen activities in over 100 fields that resulted in the transfer of approximately 0.8 GOEB from proved undeveloped to proved developed reserves by year-end. The largest transfers were relate to Papua New Guinea (PNG) LNG start-up and drilling activity in the United States.

One of ExxonMobil's requirements for reporting proved reserves is that management has made significant funding commitments toward the development of the reserves. ExxonMob has a disciplined investment strategy and many major fields require long lead-time in order to be developed. Development projects typically take two to four years from the time o recording proved undeveloped reserves to the start of production. However, the development time for large and complex projects can exceed five years. During 2014, discoveries an extensions related to new projects added approximately 0.6 GOEB of proved undeveloped reserves. The largest of these additions were related to planned drilling in the United States ar project funding in Angola, Russia and Kazakhstan. Overall, investments of $24.2 billion were made by the Corporation during 2014 to progress the development of reported prove undeveloped reserves, including $22.4 billion for oil and gas producing activities and an additional $1.8 billion for other non-oil and gas producing activities such as the construction o support infrastructure and other related facilities. These investments represented 74 percent of the $32.7 billion in total reported Upstream capital and exploration expenditures.

Proved undeveloped reserves in Australia, the United States, Kazakhstan, Nigeria, and the Netherlands have remained undeveloped for five years or more primarily due to constrain on the capacity of infrastructure, the pace of co-venturer/government funding, as well as the time required to complete development for very large projects. The Corporation is reasonab certain that these proved reserves will be produced; however, the timing and amount recovered can be affected by a number of factors including completion of development project reservoir performance, regulatory approvals, and significant changes in long-term oil and gas price levels. Of the proved undeveloped reserves that have been reported for five or mo years, 84 percent are contained in the aforementioned countries. The largest of these is related to LNG/Gas projects in Australia, where construction of the Gorgon LNG project is und way. In Kazakhstan, the proved undeveloped reserves are related to the remainder of the initial development of the offshore Kashagan field which is included in the North Caspia Production Sharing Agreement and the Tengizchevroil joint venture which includes a production license in the Tengiz – Korolev field complex. The Tengizchevroil joint venture i producing, and proved undeveloped reserves will continue to move to proved developed as approved development phases progress. In the Netherlands, the Groningen gas field has prove undeveloped reserves reported that are related to installation of future stages of compression. These reserves will move to proved developed when the additional stages of compression a 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.

	2014		2013		2012	
			(thousands of barrels daily)			
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries						
United States	304	85	283	85	274	8[illegible]
Canada/South America *(1)*	52	9	57	10	49	1[illegible]
Europe	151	28	157	27	170	3[illegible]
Africa	469	20	451	18	472	1[illegible]
Asia	293	26	313	30	319	4[illegible]
Australia/Oceania	39	20	29	19	32	1[illegible]
Total Consolidated Subsidiaries	1,308	188	1,290	189	1,316	20[illegible]
Equity Companies						
United States	63	2	61	2	61	[illegible]
Europe	5	-	6	-	4	
Asia	236	69	373	68	345	6[illegible]
Total Equity Companies	304	71	440	70	410	6[illegible]
Total crude oil and natural gas liquids production	1,612	259	1,730	259	1,726	26[illegible]
Bitumen production						
Consolidated Subsidiaries						
Canada/South America	180		148		123	
Synthetic oil production						
Consolidated Subsidiaries						
Canada/South America	60		65		69	
Total liquids production	2,111		2,202		2,185	
			(millions of cubic feet daily)			
Natural gas production available for sale						
Consolidated Subsidiaries						
United States	3,374		3,530		3,819	
Canada/South America *(1)*	310		354		362	
Europe	1,226		1,294		1,446	
Africa	4		6		17	
Asia	1,067		1,180		1,445	
Australia/Oceania	512		351		363	
Total Consolidated Subsidiaries	6,493		6,715		7,452	
Equity Companies						
United States	30		15		3	
Europe	1,590		1,957		1,774	
Asia	3,032		3,149		3,093	
Total Equity Companies	4,652		5,121		4,870	
Total natural gas production available for sale	11,145		11,836		12,322	
			(thousands of oil-equivalent barrels daily)			
Oil-equivalent production	3,969		4,175		4,239	

(1) South America includes liquids production for 2012 of one thousand barrels daily and natural gas production available for sale for 2014, 2013 and 2012 of 21 million, 28 million, [illegible] 38 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 three years.

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
During 2014				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	84.00	86.46	96.43	97.46	95.27	95.56	93.2
NGL, per barrel	39.70	51.86	53.68	65.21	40.81	56.77	47.0
Natural gas, per thousand cubic feet	3.61	3.96	8.18	2.61	3.71	5.87	4.6
Bitumen, per barrel	-	62.68	-	-	-	-	62.6
Synthetic oil, per barrel	-	89.76	-	-	-	-	89.7
Average production costs, per oil-equivalent barrel - total	13.35	33.03	22.29	12.58	8.64	11.05	15.9
Average production costs, per barrel - bitumen	-	32.66	-	-	-	-	32.6
Average production costs, per barrel - synthetic oil	-	55.32	-	-	-	-	55.3
Equity Companies							
Average production prices							
Crude oil, per barrel	91.24	-	88.68	-	93.42	-	92.8
NGL, per barrel	38.77	-	-	-	65.31	-	64.4
Natural gas, per thousand cubic feet	4.54	-	8.28	-	10.00	-	9.3
Average production costs, per oil-equivalent barrel - total	24.34	-	6.10	-	1.85	-	4.2
Total							
Average production prices							
Crude oil, per barrel	85.23	86.46	96.17	97.46	94.44	95.56	93.1
NGL, per barrel	39.68	51.86	53.68	65.21	58.52	56.77	51.8
Natural gas, per thousand cubic feet	3.62	3.96	8.23	2.61	8.36	5.87	6.6
Bitumen, per barrel	-	62.68	-	-	-	-	62.6
Synthetic oil, per barrel	-	89.76	-	-	-	-	89.7
Average production costs, per oil-equivalent barrel - total	14.10	33.03	15.59	12.58	4.44	11.05	12.5
Average production costs, per barrel - bitumen	-	32.66	-	-	-	-	32.6
Average production costs, per barrel - synthetic oil	-	55.32	-	-	-	-	55.3
During 2013							
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	93.56	98.91	106.75	108.73	106.18	107.92	104.1
NGL, per barrel	44.30	44.96	65.36	75.24	40.83	59.55	51.1
Natural gas, per thousand cubic feet	2.99	2.80	10.07	2.79	4.10	4.20	4.6
Bitumen, per barrel	-	59.63	-	-	-	-	59.6
Synthetic oil, per barrel	-	93.96	-	-	-	-	93.9
Average production costs, per oil-equivalent barrel - total	12.02	32.02	19.57	13.95	8.95	16.81	15.4
Average production costs, per barrel - bitumen	-	34.30	-	-	-	-	34.3
Average production costs, per barrel - synthetic oil	-	50.94	-	-	-	-	50.9
Equity Companies							
Average production prices							
Crude oil, per barrel	102.24	-	99.26	-	103.96	-	103.6
NGL, per barrel	42.02	-	-	-	70.90	-	69.9
Natural gas, per thousand cubic feet	4.37	-	9.28	-	10.19	-	9.8
Average production costs, per oil-equivalent barrel - total	22.77	-	3.79	-	1.87	-	3.3
Total							
Average production prices							
Crude oil, per barrel	95.11	98.91	106.49	108.73	104.98	107.92	104.0
NGL, per barrel	44.24	44.96	65.36	75.24	61.64	59.55	56.2
Natural gas, per thousand cubic feet	3.00	2.80	9.59	2.79	8.53	4.20	6.8
Bitumen, per barrel	-	59.63	-	-	-	-	59.6
Synthetic oil, per barrel	-	93.96	-	-	-	-	93.9
Average production costs, per oil-equivalent barrel - total	12.72	32.02	12.42	13.95	4.41	16.81	11.4
Average production costs, per barrel - bitumen	-	34.30	-	-	-	-	34.3
Average production costs, per barrel - synthetic oil	-	50.94	-	-	-	-	50.9

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
During 2012				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	94.71	98.67	110.91	111.19	109.95	112.12	107.0
NGL, per barrel	50.32	57.84	68.08	76.63	43.65	56.85	54.7
Natural gas, per thousand cubic feet	2.15	1.98	8.92	2.77	3.91	4.39	3.9
Bitumen, per barrel	-	58.91	-	-	-	-	58.9
Synthetic oil, per barrel	-	92.77	-	-	-	-	92.7
Average production costs, per oil-equivalent barrel - total	11.14	26.94	15.06	13.35	7.27	12.11	13.0
Average production costs, per barrel - bitumen	-	23.71	-	-	-	-	23.7
Average production costs, per barrel - synthetic oil	-	47.45	-	-	-	-	47.4
Equity Companies							
Average production prices							
Crude oil, per barrel	105.02	-	104.59	-	106.59	-	106.3
NGL, per barrel	58.38	-	-	-	75.24	-	74.8
Natural gas, per thousand cubic feet	3.22	-	9.66	-	9.38	-	9.4
Average production costs, per oil-equivalent barrel - total	20.15	-	3.36	-	1.43	-	2.8
Total							
Average production prices							
Crude oil, per barrel	96.60	98.67	110.74	111.19	108.22	112.12	106.8
NGL, per barrel	50.46	57.84	68.08	76.63	62.61	56.85	59.7
Natural gas, per thousand cubic feet	2.15	1.98	9.33	2.77	7.64	4.39	6.1
Bitumen, per barrel	-	58.91	-	-	-	-	58.9
Synthetic oil, per barrel	-	92.77	-	-	-	-	92.7
Average production costs, per oil-equivalent barrel - total	11.68	26.94	10.34	13.35	3.74	12.11	9.9
Average production costs, per barrel - bitumen	-	23.71	-	-	-	-	23.7
Average production costs, per barrel - synthetic oil	-	47.45	-	-	-	-	47.4

Average production prices have been calculated by using sales quantities from the Corporation’s own production as the divisor. Average production costs have been computed by usin net production quantities for the divisor. The volumes of crude oil and natural gas liquids (NGL) production used for this computation are shown in the oil and gas production table i section 3.A. The volumes of natural gas used in the calculation are the production volumes of natural gas available for sale and are also shown in section 3.A. The natural gas available f sale volumes are different from those shown in the reserves table in the “Oil and Gas Reserves” part of the “Supplemental Information on Oil and Gas Exploration and Productio Activities” portion of the Financial Section of this report due to volumes consumed or flared. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels.

4. Drilling and Other Exploratory and Development Activities

A. Number of Net Productive and Dry Wells Drilled

	2014	2013	201
Net Productive Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	3	8	7
Canada/South America	3	4	2
Europe	1	-	1
Africa	2	2	2
Asia	-	-	1
Australia/Oceania	-	-	2
Total Consolidated Subsidiaries	9	14	15
Equity Companies			
United States	-	-	
Europe	2	1	1
Asia	-	1	
Total Equity Companies	2	2	1
Total productive exploratory wells drilled	11	16	16
Net Dry Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	2	2	2
Canada/South America	1	4	
Europe	1	1	2
Africa	1	-	
Asia	-	-	2
Australia/Oceania	-	-	1
Total Consolidated Subsidiaries	5	7	7
Equity Companies			
United States	2	1	
Europe	-	-	1
Asia	-	-	
Total Equity Companies	2	1	1
Total dry exploratory wells drilled	7	8	8

	2014	2013	201
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
United States	721	755	867
Canada/South America	178	201	73
Europe	8	13	10
Africa	41	33	39
Asia	19	30	28
Australia/Oceania	5	3	
Total Consolidated Subsidiaries	972	1,035	1,017
Equity Companies			
United States	340	328	282
Europe	2	2	4
Asia	1	8	7
Total Equity Companies	343	338	293
Total productive development wells drilled	1,315	1,373	1,310
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	6	5	5
Canada/South America	3	-	
Europe	1	2	1
Africa	-	-	
Asia	-	-	2
Australia/Oceania	-	-	
Total Consolidated Subsidiaries	10	7	8
Equity Companies			
United States	-	-	
Europe	1	1	
Asia	-	-	
Total Equity Companies	1	1	
Total dry development wells drilled	11	8	8
Total number of net wells drilled	1,344	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 methods to extract the crude bitumen, and then upgrade it t produce a high-quality, light (32 degrees API), sweet, synthetic crude oil. Imperial Oil Limited is the owner of a 25 percent interest in the joint venture. Exxon Mobil Corporation has 69.6 percent interest in Imperial Oil Limited. In 2014, the company's share of net production of synthetic crude oil was about 60 thousand barrels per day and share of net acreage wa about 63 thousand acres in the Athabasca oil sands deposit.

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

The Kearl project is located approximately 40 miles north of Fort McMurray, Alberta, Canada. Bitumen is extracted from oil sands produced from open-pit mining operations, an processed through a bitumen extraction and froth treatment train. The product, a blend of bitumen and diluent, is shipped to our refineries and to other third parties. Diluent is natural ga condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation by pipeline. During 2014, average net production at Kearl was 66 thousand barrels per da The Kearl Expansion project was essentially complete at the end of 2014, and the commissioning of facilities commenced in preparation for start-up.

5. Present Activities

A. Wells Drilling

	Year-End 2014		Year-End 2013	
	Gross	Net	Gross	Net
Wells Drilling				
Consolidated Subsidiaries				
United States	1,120	442	1,199	48
Canada/South America	35	29	107	9
Europe	18	8	29	1
Africa	33	12	38	1
Asia	90	26	112	3
Australia/Oceania	10	4	18	[illegible]
Total Consolidated Subsidiaries	1,306	521	1,503	63
Equity Companies				
United States	31	6	9	[illegible]
Europe	4	1	8	[illegible]
Asia	1	-	11	[illegible]
Total Equity Companies	36	7	28	[illegible]
Total gross and net wells drilling	1,342	528	1,531	64

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2014 acreage holdings totaled 14.6 million net acres, of which 1.7 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in th lower 48 states and in Alaska.

During the year, 1,048.3 net exploration and development wells were completed in the inland lower 48 states. Development activities focused on liquids-rich opportunities in th onshore U.S., primarily in the Permian Basin of West Texas and New Mexico, the Bakken oil play in North Dakota and Montana, and the Woodford and Caney Shales in the Ardmore an Marietta basins of Oklahoma. In addition, gas development activities continued in the Marcellus Shale of Pennsylvania and West Virginia, the Utica Shale of Ohio, the Haynesville Shal 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 2014 was 1.5 million acres. A total of 2.6 net exploration and development wells were completed during the yea Development activities were completed on the deepwater Hadrian South project and the non-operated Lucius project. ExxonMobil continued development activities on the Heidelberg an Julia Phase 1 projects. Offshore California 5.0 net development wells were completed.

Participation in Alaska production and development continued with a total of 18.3 net development wells completed. Development activities continued on the Point Thomson project

CANADA / SOUTH AMERICA

Canada

Oil and Gas Operations: ExxonMobil's year-end 2014 acreage holdings totaled 5.4 million net acres, of which 1.0 million net acres were offshore. A total of 89.2 net development well were completed during the year.

In Situ Bitumen Operations: ExxonMobil's year-end 2014 in situ bitumen acreage holdings totaled 0.7 million net onshore acres. A total of 90.0 net development wells were complete during the year.

Argentina

ExxonMobil's net acreage totaled 0.9 million onshore acres at year-end 2014, and there were 4.6 net exploration and development wells completed during the year

EUROPE

Germany

A total of 4.9 million net onshore acres were held by ExxonMobil at year-end 2014, with 2.6 net exploration and development wells completed during the year

Netherlands

ExxonMobil's net interest in licenses totaled approximately 1.5 million acres at year-end 2014, of which 1.2 million acres were onshore. A total of 5.1 net exploration and developmer wells were completed during the year.

Norway

ExxonMobil's net interest in licenses at year-end 2014 totaled approximately 0.4 million acres, all offshore. A total of 4.9 net exploration and development wells were completed in 2014

United Kingdom

ExxonMobil's net interest in licenses at year-end 2014 totaled approximately 0.6 million acres, all offshore. A total of 2.1 net development wells were completed during the year.

AFRICA

Angola

ExxonMobil's net acreage totaled 0.4 million offshore acres at year-end 2014, with 6.7 net exploration and development wells completed during the year. On Block 15, developmer activities continued at Kizomba Satellites Phase 2. The Kaombo project on Block 32 was funded in 2014. The Cravo-Lirio-Orquidea-Violeta project, on the non-operated Block 17, starte up in 2014.

Chad

ExxonMobil's net year-end 2014 acreage holdings consisted of 46 thousand onshore acres, with 30.0 net development wells completed during the year

Equatorial Guinea

ExxonMobil's acreage totaled 0.1 million net offshore acres at year-end 2014, with 1.5 net development wells completed during the year.

Nigeria

ExxonMobil's net acreage totaled 0.8 million offshore acres at year-end 2014, with 3.6 net exploration and development wells completed during the year. In 2014, ExxonMobil continue development drilling on the deepwater Usan and Erha North Phase 2 projects. Satellite Field Development Phase 1 development drilling was completed, and the Bonga Northwe deepwater project started up in 2014.

ASIA

Azerbaijan

At year-end 2014, ExxonMobil’s net acreage totaled 9 thousand offshore acres. A total of 0.9 net development wells were completed during the year. The Chirag Oil project wa completed, and the sixth producing platform, West Chirag, started up in 2014.

Indonesia

At year-end 2014, ExxonMobil had 1.7 million net acres, 1.3 million net acres offshore and 0.4 million net acres onshore, with 7.7 net development wells completed during the year.

Iraq

At year-end 2014, ExxonMobil’s onshore acreage was 0.7 million net acres. A total of 3.0 net development wells were completed at the West Qurna Phase I oil field during the year. Fiel rehabilitation activities continued during 2014 and across the life of this project will include drilling of new wells, working over of existing wells, and optimization and debottlenecking existing facilities. In the Kurdistan Region of Iraq, ExxonMobil continued its seismic program and exploration drilling until operations were temporarily suspended due to securi concerns in the region.

Kazakhstan

ExxonMobil’s net acreage totaled 0.1 million acres onshore and 0.2 million acres offshore at year-end 2014. A total of 1.2 net development wells were completed during 2014. Followin a brief production period in 2013, Kashagan operations were suspended due to a leak in the onshore section of the gas pipeline. Working with our partners, activities are under way t replace both the oil and gas pipelines.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.2 million net acres offshore at year-end 2014. During the year, a total of 4.5 net development wells were complete The Tapis Enhanced Oil Recovery and Damar projects started up in 2014.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil’s net acreage totaled 65 thousand acres offshore at year-end 2014. During the year, a total of 0.3 net development well were completed. ExxonMobil participated in 61.8 million tonnes per year gross liquefied natural gas capacity and 2.0 billion cubic feet per day of flowing gas capacity at year en 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 2014.

Russia

ExxonMobil’s net acreage holdings in Sakhalin at year-end 2014 were 85 thousand acres, all offshore. A total of 1.2 net development wells were completed. Development activitie continued on the Arkutun-Dagi project, and the Odoptu Stage 2 project was funded in 2014.

At year-end 2014, ExxonMobil’s net acreage in the Rosneft joint venture agreements for the Kara, Laptev, Chukchi and Black Seas was 63.6 million acres, all offshore. ExxonMob and Rosneft formed a joint venture to evaluate the development of tight-oil reserves in western Siberia in 2013. Refer to the relevant portion of “Note 7: Equity Company Information” the Financial Section of this report for additional information on the Corporation’s participation in Rosneft joint venture activities.

Thailand

ExxonMobil’s net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2014

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2014. During the year, a total of 1.7 net development wells wer completed. Development activities continued on the Upper Zakum 750 project.

ExxonMobil's onshore oil concession expired in January 2014.

AUSTRALIA / OCEANIA

Australia

ExxonMobil's year-end 2014 acreage holdings totaled 1.7 million net acres, of which 1.6 million net acres were offshore. During the year, a total of 3.8 net exploration and developmen wells were completed. Construction activities continued on the Gas Conditioning Plant at Longford.

Project construction activity for the co-venturer operated Gorgon liquefied natural gas (LNG) project progressed in 2014. The project consists of a subsea infrastructure for offsho production and transportation of the gas, a 15.6 million tonnes per year LNG facility and a 280 million cubic feet per day domestic gas plant located on Barrow Island, Western Australia.

Papua New Guinea

A total of 1.1 million net onshore acres were held by ExxonMobil at year-end 2014, with 1.6 net development wells completed during the year. The Papua New Guinea (PNG) LN project started up in 2014. The PNG LNG integrated development includes gas production and processing facilities in the southern PNG Highlands, a 6.9 million tonnes per year LN facility near Port Moresby and approximately 434 miles of onshore and offshore pipelines.

WORLDWIDE EXPLORATION

At year-end 2014, exploration activities were under way in several areas in which ExxonMobil has no established production operations and thus are not included above. A total of 33. million net acres were held at year-end 2014 and 3.8 net exploration wells were completed during the year in these countries

6. Delivery Commitments

ExxonMobil sells crude oil and natural gas from its producing operations under a variety of contractual obligations, some of which may specify the delivery of a fixed and determinab quantity for periods longer than one year. ExxonMobil also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be a combination of ou own production and the spot market. Worldwide, we are contractually committed to deliver approximately 18 million barrels of oil and 2,800 billion cubic feet of natural gas for the peric from 2015 through 2017. We expect to fulfill the majority of these delivery commitments with production from our proved developed reserves. Any remaining commitments will b 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 2014				Year-End 2013			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	24,242	9,249	36,095	21,571	23,395	8,487	38,392	23,839
Canada/South America	5,012	4,659	4,577	1,782	5,486	4,990	4,478	1,762
Europe	1,215	347	642	259	1,254	352	649	269
Africa	1,299	513	19	8	1,186	472	16	6
Asia	804	267	207	150	756	270	207	151
Australia/Oceania	669	157	43	21	661	147	38	19
Total Consolidated Subsidiaries	33,241	15,192	41,583	23,791	32,738	14,718	43,780	26,046
Equity Companies								
United States	14,571	5,605	4,365	494	14,362	5,529	4,369	496
Europe	57	20	567	179	49	17	555	173
Asia	110	27	125	30	1,329	143	122	29
Total Equity Companies	14,738	5,652	5,057	703	15,740	5,689	5,046	698
Total gross and net productive wells	47,979	20,844	46,640	24,494	48,478	20,407	48,826	26,744

There were 35,446 gross and 29,870 net operated wells at year-end 2014 and 37,661 gross and 31,823 net operated wells at year-end 2013. The number of wells with multiple completion was 1,219 gross in 2014 and 1,531 gross in 2013.

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B. Gross and Net Developed Acreage

	Year-End 2014		Year-End 2013	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	14,777	9,367	16,504	10,061
Canada/South America *(1)*	3,515	2,242	3,413	2,041
Europe	3,337	1,506	3,355	1,511
Africa	2,286	815	2,105	780
Asia	1,817	551	1,828	557
Australia/Oceania	2,123	758	2,123	758
Total Consolidated Subsidiaries	27,855	15,239	29,328	15,708
Equity Companies				
United States	949	208	968	241
Europe	4,342	1,356	4,341	1,356
Asia	628	156	5,731	640
Total Equity Companies	5,919	1,720	11,040	2,237
Total gross and net developed acreage	33,774	16,959	40,368	17,945

(1) Includes developed acreage in South America of 213 gross and 109 net thousands of acres for 2014 and 214 gross and 109 net thousands of acres for 2013.

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 2014		Year-End 2013	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	10,262	4,894	7,645	4,722
Canada/South America *(1)*	16,100	12,250	16,267	9,232
Europe	10,601	5,636	13,461	6,585
Africa	22,143	15,020	20,877	13,446
Asia	17,437	13,016	18,639	13,979
Australia/Oceania	6,653	2,013	7,144	1,991
Total Consolidated Subsidiaries	83,196	52,829	84,033	49,955
Equity Companies				
United States	350	118	363	121
Europe	-	-	-	
Asia	191,146	63,632	34,147	11,352
Total Equity Companies	191,496	63,750	34,510	11,473
Total gross and net undeveloped acreage	274,692	116,579	118,543	61,428

(1) Includes undeveloped acreage in South America of 9,056 gross and 8,083 net thousands of acres for 2014 and 8,795 gross and 4,674 net thousands of acres for 2013.

Note: Year-end 2013 gross developed and undeveloped acreage in Canada/South America was restated.

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

D. Summary of Acreage Terms

UNITED STATES

Oil and gas leases have an exploration period ranging from one to ten years, and a production period that normally remains in effect until production ceases. Under certain circumstance a lease may be held beyond its exploration term even if production has not commenced. In some instances, a "fee interest" is acquired where both the surface and the underlying miner interests are owned outright.

CANADA / SOUTH AMERICA

Canada

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

Argentina

The Federal Hydrocarbon Law was amended in December 2014. The onshore concession terms granted prior to the amendment are up to six years, divided into three potential exploratic periods, with an optional extension for up to one year depending on the classification of the area. Pursuant to the amended law, the production term for a conventional productic concession would be 25 years, and 35 years for an unconventional concession, with unlimited ten-year extensions possible, once a field has been developed.

EUROPE

Germany

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

Netherlands

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

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

Norway

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

United Kingdom

Acreage terms are fixed by the government and are periodically changed. For example, many of the early licenses issued under the first four licensing rounds provided for an initial term of six years with relinquishment of at least one-half of the original area at the end of the initial term, subject to extension for a further 40 years. At the end of any such 40-year term, licenses may continue in producing areas until cessation of production; or licenses may continue in development areas for periods agreed on a case-by-case basis until they become producing areas; or licenses terminate in all other areas. The licensing regime was last updated in 2002, and the majority of licenses issued have an initial term of four years with a second term extension of four years and a final term of 18 years with a mandatory relinquishment of 50 percent of the acreage after the initial term and of all acreage that is not covered by a development plan at the end of the second term.

AFRICA

Angola

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

Chad

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

Equatorial Guinea

Exploration and production activities are governed by production sharing contracts negotiated with the State Ministry of Mines, Industry and Energy. The exploration periods are for 10 to 15 years with limited relinquishments in the absence of commercial discoveries. The production period for crude oil is 30 years, while the production period for gas is 50 years. Under the Hydrocarbons Law enacted in 2006, the exploration terms for new production sharing contracts are four to five years with a maximum of two one-year extensions, unless the Ministry agrees otherwise.

Nigeria

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

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

OMLs granted prior to the 1969 Petroleum Act (i.e., under the Mineral Oils Act 1914, repealed by the 1969 Petroleum Act) were for 30 years onshore and 40 years in offshore areas and have been renewed, effective December 1, 2008, for a further period of 20 years, with a further renewal option of 20 years. Operations under these pre-1969 OMLs are conducted under a joint venture agreement with NNPC rather than a PSC. Commercial terms applicable to the existing joint venture oil production are defined by the Petroleum Profits Tax Act.

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

ASIA

Azerbaijan

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

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

Indonesia

Exploration and production activities in Indonesia are generally governed by cooperation contracts, usually in the form of a production sharing contract (PSC), negotiated with BPMIGA: a government agency established in 2002 to manage upstream oil and gas activities. In 2012, Indonesia's Constitutional Court ruled certain articles of law relating to BPMIGAS to b unconstitutional, but stated that all existing PSCs signed with BPMIGAS should remain in force until their expiry, and the functions and duties previously performed by BPMIGAS are t be carried out by the relevant Ministry of the Government of Indonesia until the promulgation of a new oil and gas law. By presidential decree, SKKMIGAS became the interim successo to BPMIGAS. The current PSCs have an exploration period of six years, which can be extended up to 10 years, and an exploitation period of 20 years. PSCs generally require tl contractor to relinquish 10 percent to 20 percent of the contract area after three years and generally allow the contractor to retain no more than 50 percent to 80 percent of the origin contract area after six years, depending on the acreage and terms.

Iraq

Development and production activities in the state-owned oil and gas fields are governed by contracts with regional oil companies of the Iraqi Ministry of Oil. An ExxonMobil affiliat entered into a contract with South Oil Company of the Iraqi Ministry of Oil for the rights to participate in the development and production activities of the West Qurna Phase I oil and ga field effective March 1, 2010. The term of the contract is 20 years with the right to extend for five years. The contract provides for cost recovery plus per-barrel fees for increment production above specified levels.

Exploration and production activities in the Kurdistan Region of Iraq are governed by production sharing contracts negotiated with the regional government of Kurdistan in 2011. Tl exploration term is for five years with the possibility of two-year extensions. The production period is 20 years with the right to extend for five years.

Kazakhstan

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

Offshore exploration and production activities are governed by a production sharing agreement negotiated with the Republic of Kazakhstan. The exploration period is six years follow by separate appraisal periods for each discovery. The production period for each discovery, which includes development, is for 20 years from the date of declaration of commerciality wit the possibility of two ten-year extensions.

Malaysia

Production activities are governed by production sharing contracts (PSCs) negotiated with the national oil company. The PSCs have terms ranging up to 29 years. All extensions ar subject to the national oil company's prior written approval. The total production period is 15 to 29 years, depending on the date of the execution of the contract and the date of fir commercial lifting.

Qatar

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

Republic of Yemen

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

Russia

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

Exploration and production activities in the Kara, Laptev, Chukchi and Black Seas are governed by joint venture agreements concluded with Rosneft in 2013 and 2014 that cove certain of Rosneft's offshore licenses. The Kara Sea licenses covered by the joint venture agreements concluded in 2013 extend through 2040 and include an exploration period throug 2020. Additional licenses in the Kara, Laptev and Chukchi Seas covered by the joint venture agreements concluded in 2014 extend through 2043 and include an exploration period throug 2023. The Kara, Laptev and Chukchi Sea licenses require development plan submission within eight years of a discovery and development activities within five years of plan approval. T Black Sea exploration license extends through 2017 and a discovery is the basis for obtaining a license for production. Refer to the relevant portion of "Note 7: Equity Compar Information" of the Financial Section of this report for additional information on the Corporation's participation in Rosneft joint venture activities.

Thailand

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

United Arab Emirates

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

AUSTRALIA/OCEANIA

Australia

Exploration and production activities conducted offshore in Commonwealth waters are governed by Federal legislation. Exploration permits are granted for an initial term of six years wi two possible five-year renewal periods. Retention leases may be granted for resources that are not commercially viable at the time of application, but are expected to become commerciall viable within 15 years. These are granted for periods of five years and renewals may be requested. Prior to July 1998, production licenses were granted initially for 21 years, with a furth renewal of 21 years and thereafter "indefinitely", i.e., for the life of the field. Effective from July 1998, new production licenses are granted "indefinitely". In each case, a productic license may be terminated if no production operations have been carried on for five years.

Papua New Guinea

Exploration and production activities are governed by the Oil and Gas Act. Petroleum Prospecting licenses are granted for an initial term of six years with a five-year extension possibl (an additional extension of three years is possible in certain circumstances). Generally, a 50-percent relinquishment of the license area is required at the end of the initial six-year term, extended. Petroleum Development licenses are granted for an initial 25-year period. An extension of up to 20 years may be granted at the Minister's discretion. Petroleum Retentio licenses may be granted for gas resources that are not commercially viable at the time of application, but may become commercially viable within the maximum possible retention time 15 years. Petroleum Retention licenses are granted for five-year terms, and may be extended, at the Minister's discretion, twice for the maximum retention time of 15 years. Extensions Petroleum Retention licenses may be for periods of less than one year, renewable annually, if the Minister considers at the time of extension that the resources could become commerciall viable in less than five years.

Information with regard to the Downstream segment follows:

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

Refining Capacity At Year-End 2014 *(1)*

		ExxonMobil Share KBD *(2)*	ExxonMobil 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	74.9
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)		256	
Total Asia Pacific		1,015	
Other Non-U.S.			
Yanbu	Saudi Arabia	200	50
Laffan	Qatar	15	10
Total Other Non-U.S.		215	
Total Worldwide		5,248	

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

(2) Thousands of barrels per day (KBD). ExxonMobil share reflects 100 percent of atmospheric distillation capacity in operations of ExxonMobil and majority-owned subsidiaries. companies owned 50 percent or less, ExxonMobil share is the greater of ExxonMobil's 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 2014

United States	
Owned/leased	-
Distributors/resellers	9,436
Total United States	9,436
Canada	
Owned/leased	473
Distributors/resellers	1,256
Total Canada	1,729
Europe	
Owned/leased	3,209
Distributors/resellers	3,049
Total Europe	6,258
Asia Pacific	
Owned/leased	653
Distributors/resellers	757
Total Asia Pacific	1,410
Latin America	
Owned/leased	15
Distributors/resellers	734
Total Latin America	749
Middle East/Africa	
Owned/leased	404
Distributors/resellers	231
Total Middle East/Africa	635
Worldwide	
Owned/leased	4,754
Distributors/resellers	15,463
Total Worldwide	20,217

Information with regard to the Chemical segment follows:

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

Chemical Complex Capacity At Year-End 2014 *(1)(2)*

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest %
North America						
Baton Rouge	Louisiana	1.0	1.3	0.4	-	100
Baytown	Texas	2.2	-	0.7	0.6	100
Beaumont	Texas	0.9	1.0	-	0.3	100
Mont Belvieu	Texas	-	1.0	-	-	100
Sarnia	Ontario	0.3	0.5	-	-	69.6
Total North America		4.4	3.8	1.1	0.9	
Europe						
Antwerp	Belgium	-	0.4	-	-	100
Fife	United Kingdom	0.4	-	-	-	50
Meerhout	Belgium	-	0.5	-	-	100
Gravenchon	France	0.4	0.4	0.3	-	100
Rotterdam	Netherlands	-	-	-	0.7	100
Total Europe		0.8	1.3	0.3	0.7	
Middle East						
Al Jubail	Saudi Arabia	0.6	0.7	-	-	50
Yanbu	Saudi Arabia	1.0	0.7	0.2	-	50
Total Middle East		1.6	1.4	0.2	-	
Asia Pacific						
Fujian	China	0.3	0.2	0.2	0.2	25
Singapore	Singapore	1.9	1.9	0.9	1.0	100
Sriracha	Thailand	-	-	-	0.5	66
Total Asia Pacific		2.2	2.1	1.1	1.7	
All Other		-	-	-	0.1	
Total Worldwide		9.0	8.6	2.7	3.4	

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

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

ITEM 3. LEGAL PROCEEDINGS

Regarding the discussions between Chalmette Refining LLC (CRLLC), owner of the Chalmette Refinery (operated by ExxonMobil Oil Corporation), and the Louisiana Department o Environmental Quality (LDEQ) to resolve self-reported deviations from refinery operations and relating to certain Clean Air Act Title V permit conditions, limits and other requirement reported in the Corporation's Form 10-Q for the second quarter of 2012, on November 14, 2014, CRLLC received a Consolidated Compliance Order and Notice of Potential Penalt (CCO/NOPP) from LDEQ covering the deviations between 2009 and 2010. CRLLC and LDEQ have entered a dispute resolution agreement, which suspends enforcement of th CCO/NOPP while negotiations are ongoing.

Regarding allegations raised by LDEQ concerning the April 28, 2012, discharge of crude oil from the ExxonMobil Pipeline Company's (EMPCo) North Line Pipeline near Torbert i Pointe Coupee Parish, Louisiana, previously reported in the Corporation's Forms 10-Q for the third quarter of 2013 and the third quarter of 2014, on December 9, 2014, LDEQ notifie EMPCo that it was seeking a Penalty Assessment of $471,000 related to the discharge. EMPCo has timely requested an adjudicatory hearing on disputed issues of fact and law related t the proposed penalty assessment.

With respect to the enforcement action filed by the United States, on behalf of the United States Environmental Protection Agency (USEPA), and the State of Arkansas, on behalf of th Arkansas Department of Environmental Quality, against EMPCo related to the discharge of crude oil from the Pegasus Pipeline in Mayflower, Faulkner County, Arkansas, previousl reported in the Corporation's Forms 10-Q for the first, second and third quarters of 2013 and the first and second quarters of 2014, a motion has been filed to extend an earlier cou approved stay of discovery to allow the parties to pursue settlement discussions.

Regarding the $1.7 million penalty assessment against EMPCo by the U.S. Department of Transportation Pipeline & Hazardous Materials Safety Administration (PHMSA) for allege violations of the federal Pipeline Safety Regulations in connection with the July 1, 2011, discharge of crude oil into the Yellowstone River from EMPCo's Silvertip Pipeline near Laure Montana, reported in the Corporation's Forms 10-Q for the first and second quarters of 2013 and the second quarter of 2014, following a 2013 administrative hearing requested by EMPC to contest PHMSA allegations and the proposed penalty, on January 23, 2015, PHMSA announced a final order reducing the penalty to $1.05 million. On February 12, 2015, EMPC filed a motion for reconsideration of the final order.

With respect to the administrative orders alleging Clean Water Act violations issued by the USEPA with regard to three locations of XTO Energy, Inc. (XTO) in West Virginia and the five unresolved additional West Virginia sites voluntarily disclosed by XTO to the USEPA reported in the Corporation's Forms 10-Q for the first quarter of 2012 and the first three quarte of 2014, in December 2014, XTO agreed to a settlement with the Department of Justice, USEPA and West Virginia Department of Environmental Protections (WVDEP) pursuant t which XTO would pay a civil penalty of $2.3 million and enter into a Consent Decree with the Department of Justice, USEPA and WVDEP. The Consent Decree requires XTO to prepar and submit restoration plans for approval by USEPA and WVDEP and conduct approximately $3.0 million in restoration and mitigation activities at the impacted locations or at alternati locations approved by the USEPA and WVDEP. The Consent Decree is subject to Court approval. On January 6, 2015, the Justice Department published a notice in the Federal Registe stating that the Consent Decree had been lodged with the Court and soliciting public comment for a period of 30 days.

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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: 62

Mr. Rex W. Tillerson became a Director and President of Exxon Mobil Corporation on March 1, 2004. He became Chairman of the Board and Chief Executive Officer on January 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: 58

Mr. Mark W. Albers became Senior Vice President of Exxon Mobil Corporation on April 1, 2007, a position he still holds as of this filing date.

Michael J. Dolan	*Senior Vice President*	
Held current title since:	April 1, 2008	Age: 61

Mr. Michael J. Dolan became Senior Vice President of Exxon Mobil Corporation on April 1, 2008, a position he still holds as of this filing date.

Andrew P. Swiger	*Senior Vice President*	
Held current title since:	April 1, 2009	Age: 58

Mr. Andrew P. Swiger became Senior Vice President of Exxon Mobil Corporation on April 1, 2009, a position he still holds as of this filing date.

Jack P. Williams, Jr.	*Senior Vice President*	
Held current title since:	June 1, 2014	Age: 51

Mr. Jack P. Williams, Jr. was Vice President of ExxonMobil Development Company May 1, 2009 – July 1, 2010. He was President of XTO Energy Inc. June 25, 2010 – May 31, 201 He was Executive Vice President of ExxonMobil Production Company June 1, 2013 – June 30, 2014. He became Senior Vice President of Exxon Mobil Corporation on June 1, 2014, position he still holds as of this filing date.

Darren W. Woods	*Senior Vice President*	
Held current title since:	June 1, 2014	Age: 50

Mr. Darren W. Woods was Director, Refining Europe/Africa/Middle East, ExxonMobil Refining & Supply Company February 1, 2008 – June 30, 2010. He was Vice Presiden Supply & Transportation, ExxonMobil Refining & Supply Company July 1, 2010 – July 31, 2012. He was President of ExxonMobil Refining & Supply Company August 1, 2012 July 31, 2014 and Vice President of Exxon Mobil Corporation August 1, 2012 – May 31, 2014. He became Senior Vice President of Exxon Mobil Corporation on June 1, 2014, position he still holds as of this filing date.

S. Jack Balagia	*Vice President and General Counsel*	
Held current title since:	March 1, 2010	Age: 63

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

Neil A. Chapman *Vice President*

Held current title since: January 1, 2015 Age: 52

Mr. Neil A. Chapman was President of ExxonMobil Global Services Company April 4, 2007 – March 31, 2011. He was Senior Vice President, ExxonMobil Chemical Company Apr 1, 2011 – December 31, 2014. He became President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation on January 1, 2015, positions he still holds a of this filing date.

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

Held current title since: June 1, 2013 Age: 53

Mr. Randy J. Cleveland was Planning & Commercial Manager, ExxonMobil Production Company May 1, 2009 – June 24, 2010. He was Vice President, XTO Integration, XTO Energ Inc. June 25, 2010 – January 31, 2012. He was Executive Vice President, XTO Energy Inc. February 1, 2012 – May 31, 2013. He became President of XTO Energy Inc. on June 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: 61

Mr. William M. Colton became Vice President – Corporate Strategic Planning of Exxon Mobil Corporation on February 1, 2009, a position he still holds as of this filing date.

Michael G. Cousins *Vice President*

Held current title since: March 1, 2013 Age: 54

Mr. Michael G. Cousins was Vice President, Asia Pacific/Middle East, ExxonMobil Exploration Company June 1, 2009 – March 31, 2012. He was Executive Assistant to th Chairman, Exxon Mobil Corporation April 1, 2012 – February 28, 2013. He became President of ExxonMobil Upstream Ventures and Vice President of Exxon Mobil Corporation o 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: 58

Mr. Neil W. Duffin became President of ExxonMobil Development Company on April 13, 2007, a position he still holds as of this filing date.

Robert S. Franklin *Vice President*

Held current title since: May 1, 2009 Age: 57

Mr. Robert S. Franklin was President of ExxonMobil Upstream Ventures and Vice President of Exxon Mobil Corporation May 1, 2009 – February 28, 2013. He became President o ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Stephen M. Greenlee *Vice President*

Held current title since: September 1, 2010 Age: 57

Mr. Stephen M. Greenlee was President of ExxonMobil Upstream Research Company June 1, 2009 – August 31, 2010. He became President of ExxonMobil Exploration Company ar 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: 57

Mr. Alan J. Kelly became President of ExxonMobil Lubricants & Petroleum Specialties Company and Vice President of Exxon Mobil Corporation on December 1, 2007. C February 1, 2012, the businesses of ExxonMobil Lubricants & Petroleum Specialties Company and ExxonMobil Fuels Marketing Company were consolidated and Mr. Kelly becam President of the combined ExxonMobil Fuels, Lubricants & Specialties Marketing Company and Vice President of Exxon Mobil Corporation, positions he still holds as of this filir date.

David S. Rosenthal	*Vice President and Controller*	
Held current title since:	October 1, 2008 (Vice President) September 1, 2014 (Controller)	Age: 58

Mr. David S. Rosenthal was Vice President – Investor Relations and Secretary of Exxon Mobil Corporation October 1, 2008 – August 31, 2014. He became Vice President an Controller of Exxon Mobil Corporation on September 1, 2014, positions he still holds as of this filing date.

Robert N. Schleckser	*Vice President and Treasurer*	
Held current title since:	May 1, 2011	Age: 58

Mr. Robert N. Schleckser was Assistant Treasurer of Exxon Mobil Corporation February 1, 2009 – April 30, 2011. He became Vice President and Treasurer of Exxon Mob 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: 53

Mr. James M. Spellings, Jr. was Associate General Tax Counsel of Exxon Mobil Corporation April 1, 2007 – March 1, 2010. He became Vice President and General Tax Counsel c 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: 60

Mr. Thomas R. Walters was President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation April 1, 2009 – February 28, 2013. H became President of ExxonMobil Production Company and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Dennis G. Wascom	*Vice President*	
Held current title since:	August 1, 2014	Age: 58

Mr. Dennis G. Wascom was Director, Refining Americas, ExxonMobil Refining & Supply Company April 1, 2009 – June 30, 2013. He was Director, Refining North Americ ExxonMobil Refining & Supply Company July 1, 2013 – July 31, 2014. He became President of ExxonMobil Refining & Supply Company and Vice President of Exxon Mob Corporation on August 1, 2014, positions he still holds as of this filing date.

Jeffrey J. Woodbury	*Vice President – Investor Relations and Secretary*	
Held current title since:	July 1, 2011 (Vice President) September 1, 2014 (Secretary)	Age: 54

Mr. Jeffrey J. Woodbury was Executive Vice President of ExxonMobil Development Company April 1, 2009 – June 30, 2011. He was Vice President, Safety, Security, Health an Environment of Exxon Mobil Corporation July 1, 2011 – August 31, 2014. He became Vice President – Investor Relations and Secretary of Exxon Mobil Corporation on September 2014, positions he still holds as of this filing date.

Officers are generally elected by the Board of Directors at its meeting on the day of each annual election of directors, with each such officer serving until a successor has been electe 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, 2014

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 2014	11,934,362	93.06	11,934,362	
November 2014	9,803,071	95.42	9,803,071	
December 2014	13,899,727	91.55	13,899,727	
Total	35,637,160	93.12	35,637,160	(See note 1)

Note 1 - On August 1, 2000, the Corporation announced its intention to resume purchases of shares of its common stock for the treasury both to offset shares issued in conjunction wit company benefit plans and programs and to gradually reduce the number of shares outstanding. The announcement did not specify an amount or expiration date. The Corporation ha continued to purchase shares since this announcement and to report purchased volumes in its quarterly earnings releases. In its most recent earnings release dated February 2, 2015, th Corporation stated that first quarter 2015 share purchases to reduce shares outstanding are anticipated to equal $1 billion. Purchases may be made in both the open market and throug negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice.

ITEM 6. SELECTED FINANCIAL DATA

	Years Ended December 31,				
	2014	2013	2012	2011	2010
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	394,105	420,836	451,509	467,029	370,12
(1) Sales-based taxes included	*29,342*	*30,589*	*32,409*	*33,503*	*28,54*
Net income attributable to ExxonMobil	32,520	32,580	44,880	41,060	30,46
Earnings per common share	7.60	7.37	9.70	8.43	6.2
Earnings per common share - assuming dilution	7.60	7.37	9.70	8.42	6.2
Cash dividends per common share	2.70	2.46	2.18	1.85	1.7
Total assets	349,493	346,808	333,795	331,052	302,51
Long-term debt	11,653	6,891	7,928	9,322	12,22

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

- Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP dated February 25, 2015, beginning with the section entitled "Report of Independent Registered Public Accounting Firm" and continuing through "Note 19: Income, Sales-Based and Other Taxes";
- "Quarterly Information" (unaudited);
- "Supplemental Information on Oil and Gas Exploration and Production Activities" (unaudited); and
- "Frequently Used Terms" (unaudited).

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

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

As indicated in the certifications in Exhibit 31 of this report, the Corporation's Chief Executive Officer, Principal Financial Officer and Principal Accounting Officer have evaluated th Corporation's disclosure controls and procedures as of December 31, 2014. Based on that evaluation, these officers have concluded that the Corporation's disclosure controls an procedures are effective in ensuring that information required to be disclosed by the Corporation in the reports that it files or submits under the Securities Exchange Act of 1934, a amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

Management's Report on Internal Control Over Financial Reporting

Management, including the Corporation's Chief Executive Officer, Principal Financial Officer and Principal Accounting Officer, is responsible for establishing and maintaining adequat internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criter established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, manageme concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2014.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as c December 31, 2014, as stated in their report included in the Financial Section of this report.

Changes in Internal Control Over Financial Reporting

There were no changes during the Corporation's last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financia 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 2015 annual meeting of shareholders (the "2015 Proxy Statement"):

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

ITEM 11. EXECUTIVE COMPENSATION

Incorporated by reference to the sections entitled "Director Compensation," "Compensation Committee Report," "Compensation Discussion and Analysis" and "Executive Compensatic Tables" of the registrant's 2015 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTE

The information required under Item 403 of Regulation S-K is incorporated by reference to the sections "Director and Executive Officer Stock Ownership" and "Certain Benefici Owners" of the registrant's 2015 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 Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	24,243,615 *(1)*	-	109,066,057 *(2)(3)*
Equity compensation plans not approved by security holders	-	-	-
Total	24,243,615	-	109,066,057

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

(2) Available shares can be granted in the form of restricted stock, options, or other stock-based awards. Includes 108,454,857 shares available for award under the 2003 Incen Program and 611,200 shares available for award under the 2004 Non-Employee Director Restricted Stock Plan.

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Incorporated by reference to the portions entitled “Related Person Transactions and Procedures” and “Director Independence” of the section entitled “Corporate Governance” of tl registrant’s 2015 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Incorporated by reference to the portion entitled “Audit Committee” of the section entitled “Corporate Governance” and the section entitled “Ratification of Independent Auditors” of th registrant’s 2015 Proxy Statement.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

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

FINANCIAL SECTION

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BUSINESS PROFILE

Financial	Earnings After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
	2014	2013	2014	2013	2014	2013	2014	2013
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	5,197	4,191	62,403	59,898	8.3	7.0	9,401	9,143
Non-U.S.	22,351	22,650	102,562	93,071	21.8	24.3	23,326	29,086
Total	27,548	26,841	164,965	152,969	16.7	17.5	32,727	38,231
Downstream								
United States	1,618	2,199	6,070	4,757	26.7	46.2	1,310	951
Non-U.S.	1,427	1,250	17,907	19,673	8.0	6.4	1,724	1,462
Total	3,045	3,449	23,977	24,430	12.7	14.1	3,034	2,413
Chemical								
United States	2,804	2,755	6,121	4,872	45.8	56.5	1,690	963
Non-U.S.	1,511	1,073	16,076	15,793	9.4	6.8	1,051	869
Total	4,315	3,828	22,197	20,665	19.4	18.5	2,741	1,832
Corporate and financing	(2,388)	(1,538)	(8,029)	(6,489)	-	-	35	13
Total	32,520	32,580	203,110	191,575	16.2	17.2	38,537	42,489

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

Operating	2014	2013
	(thousands of barrels daily)	
Net liquids production		
United States	454	431
Non-U.S.	1,657	1,771
Total	2,111	2,202
	(millions of cubic feet daily)	
Natural gas production available for sale		
United States	3,404	3,545
Non-U.S.	7,741	8,291
Total	11,145	11,836
	(thousands of oil-equivalent barrels daily)	
Oil-equivalent production *(1)*	3,969	4,175

	2014	2013
	(thousands of barrels daily)	
Refinery throughput		
United States	1,809	1,819
Non-U.S.	2,667	2,766
Total	4,476	4,585
	(thousands of barrels daily)	
Petroleum product sales		
United States	2,655	2,609
Non-U.S.	3,220	3,278
Total	5,875	5,887
	(thousands of metric tons)	
Chemical prime product sales *(2)*		
United States	9,528	9,679
Non-U.S.	14,707	14,384
Total	24,235	24,063

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

(2) Prime product sales are total product sales excluding carbon black oil and sulfur. Prime product sales include ExxonMobil's share of equity company volumes and finish product transfers to the Downstream.

FINANCIAL SUMMARY

	2014	2013	2012	2011	2010
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	394,105	420,836	451,509	467,029	370,12
Earnings					
Upstream	27,548	26,841	29,895	34,439	24,09
Downstream	3,045	3,449	13,190	4,459	3,56
Chemical	4,315	3,828	3,898	4,383	4,91
Corporate and financing	(2,388)	(1,538)	(2,103)	(2,221)	(2,11
Net income attributable to ExxonMobil	32,520	32,580	44,880	41,060	30,46
Earnings per common share	7.60	7.37	9.70	8.43	6.2
Earnings per common share – assuming dilution	7.60	7.37	9.70	8.42	6.2
Cash dividends per common share	2.70	2.46	2.18	1.85	1.7
Earnings to average ExxonMobil share of equity (percent)	18.7	19.2	28.0	27.3	23.
Working capital	(11,723)	(12,416)	321	(4,542)	(3,64
Ratio of current assets to current liabilities (times)	0.82	0.83	1.01	0.94	0.9
Additions to property, plant and equipment	34,256	37,741	35,179	33,638	74,15
Property, plant and equipment, less allowances	252,668	243,650	226,949	214,664	199,54
Total assets	349,493	346,808	333,795	331,052	302,51
Exploration expenses, including dry holes	1,669	1,976	1,840	2,081	2,14
Research and development costs	971	1,044	1,042	1,044	1,01
Long-term debt	11,653	6,891	7,928	9,322	12,22
Total debt	29,121	22,699	11,581	17,033	15,01
Fixed-charge coverage ratio (times)	46.9	55.7	62.4	53.4	42.
Debt to capital (percent)	13.9	11.2	6.3	9.6	9.
Net debt to capital (percent) *(2)*	11.9	9.1	1.2	2.6	4.
ExxonMobil share of equity at year-end	174,399	174,003	165,863	154,396	146,83
ExxonMobil share of equity per common share	41.51	40.14	36.84	32.61	29.4
Weighted average number of common shares outstanding (millions)	4,282	4,419	4,628	4,870	4,88
Number of regular employees at year-end (thousands) *(3)*	75.3	75.0	76.9	82.1	83.
CORS employees not included above (thousands) *(4)*	8.4	9.8	11.1	17.0	20.

(1) Sales and other operating revenue includes sales-based taxes of $29,342 million for 2014, $30,589 million for 2013, $32,409 million for 2012, $33,503 million for 2011 and $28, million for 2010.

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

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

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

FREQUENTLY USED TERMS

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

Cash Flow From Operations and Asset Sales

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

Cash flow from operations and asset sales	**2014**	**2013**	**2012**
		(millions of dollars)	
Net cash provided by operating activities	45,116	44,914	56,170
Proceeds associated with sales of subsidiaries, property, plant and equipment,			
and sales and returns of investments	4,035	2,707	7,655
Cash flow from operations and asset sales	49,151	47,621	63,825

Capital Employed

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

Capital employed	**2014**	**2013**	**2012**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	349,493	346,808	333,795
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(47,165)	(55,916)	(60,486)
Total long-term liabilities excluding long-term debt	(92,143)	(87,698)	(90,068)
Noncontrolling interests share of assets and liabilities	(9,099)	(8,935)	(6,235)
Add ExxonMobil share of debt-financed equity company net assets	4,766	6,109	5,775
Total capital employed	205,852	200,368	182,787
Total corporate sources: debt and equity perspective			
Notes and loans payable	17,468	15,808	3,653
Long-term debt	11,653	6,891	7,928
ExxonMobil share of equity	174,399	174,003	165,863
Less noncontrolling interests share of total debt	(2,434)	(2,443)	(438)
Add ExxonMobil share of equity company debt	4,766	6,109	5,775
Total capital employed	205,852	200,368	182,787

FREQUENTLY USED TERMS

Return on Average Capital Employed

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

Return on average capital employed	**2014**	**2013**	**2012**
		(millions of dollars)	
Net income attributable to ExxonMobil	32,520	32,580	44,88
Financing costs (after tax)			
Gross third-party debt	(140)	(163)	(40
ExxonMobil share of equity companies	(256)	(239)	(25
All other financing costs – net	(68)	83	10
Total financing costs	(464)	(319)	(55
Earnings excluding financing costs	32,984	32,899	45,43
Average capital employed	203,110	191,575	179,09
Return on average capital employed – corporate total	16.2%	17.2%	25.4

QUARTERLY INFORMATION

	2014					2013				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Year**	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Year**
Volumes										
Production of crude oil					*(thousands of barrels daily)*					
and natural gas liquids, synthetic oil and bitumen	2,148	2,048	2,065	2,182	2,111	2,193	2,182	2,199	2,235	2,20
Refinery throughput	4,509	4,454	4,591	4,349	4,476	4,576	4,466	4,847	4,452	4,58
Petroleum product sales	5,817	5,841	5,999	5,845	5,875	5,755	5,765	6,031	5,994	5,88
Natural gas production					*(millions of cubic feet daily)*					
available for sale	12,016	10,750	10,595	11,234	11,145	13,213	11,354	10,914	11,887	11,83
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production *(1)*	4,151	3,840	3,831	4,054	3,969	4,395	4,074	4,018	4,216	4,17
					(thousands of metric tons)					
Chemical prime product sales	6,128	6,139	6,249	5,719	24,235	5,910	5,831	6,245	6,077	24,06
Summarized financial data										
Sales and other operating					*(millions of dollars)*					
revenue *(2)(3)*	101,312	105,719	103,206	83,868	394,105	103,378	103,050	108,390	106,018	420,83
Gross profit *(4)*	29,166	28,746	28,825	23,240	109,977	30,083	28,689	30,300	29,901	118,97
Net income attributable to ExxonMobil	9,100	8,780	8,070	6,570	32,520	9,500	6,860	7,870	8,350	32,58
Per share data					*(dollars per share)*					
Earnings per common share *(5)*	2.10	2.05	1.89	1.56	7.60	2.12	1.55	1.79	1.91	7.3
Earnings per common share – assuming dilution *(5)*	2.10	2.05	1.89	1.56	7.60	2.12	1.55	1.79	1.91	7.3
Dividends per common share	0.63	0.69	0.69	0.69	2.70	0.57	0.63	0.63	0.63	2.4
Common stock prices										
High	101.22	104.61	104.76	97.20	104.76	91.93	93.50	95.49	101.74	101.7
Low	89.25	96.24	93.62	86.19	86.19	86.59	85.02	85.61	84.79	84.7

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

(2) Amounts in first three quarters of 2014 have been reclassified.

(3) Includes amounts for sales-based taxes.

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

(5) Computed using the average number of shares outstanding during each period. The sum of the four quarters may not add to the full year.

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

There were 433,941 registered shareholders of ExxonMobil common stock at December 31, 2014. At January 31, 2015, the registered shareholders of ExxonMobil common stoc numbered 432,983.

On January 28, 2015, the Corporation declared a $0.69 dividend per common share, payable March 10, 2015.

FUNCTIONAL EARNINGS	**2014**	**2013**	**2012**
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	5,197	4,191	3,92
Non-U.S.	22,351	22,650	25,97
Downstream			
United States	1,618	2,199	3,57
Non-U.S.	1,427	1,250	9,61
Chemical			
United States	2,804	2,755	2,22
Non-U.S.	1,511	1,073	1,67
Corporate and financing	(2,388)	(1,538)	(2,10
Net income attributable to ExxonMobil (U.S. GAAP)	32,520	32,580	44,88
Earnings per common share	7.60	7.37	9.7
Earnings per common share – assuming dilution	7.60	7.37	9.7

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

FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual future results, including demand growth and energ source mix; capacity increases; production growth and mix; rates of field decline; financing sources; the resolution of contingencies and uncertain tax positions; environmental and capit expenditures; could differ materially depending on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical product the outcome of commercial negotiations; political or regulatory events, and other factors discussed herein and in Item 1A. Risk Factors.

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

OVERVIEW

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

ExxonMobil, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develo new energy supplies. While commodity prices are volatile on a short-term basis and depend on supply and demand, ExxonMobil’s investment decisions are based on our long-terr business outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process th is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes ar based on individual field production profiles, which are also updated annually. Price ranges for crude oil, natural gas, refined products, and chemical products are based on corporate pla assumptions developed annually by major region and are utilized for investment evaluation purposes. Potential investment opportunities are evaluated over a wide range of econom scenarios to establish the resiliency of each opportunity. Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements ar 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 9 billion people, or about 2 billion more than in 2010. Coincident with this population increase, the Corporatic expects worldwide economic growth to average close to 3 percent per year. As economies and populations grow, and as living standards improve for billions of people, the need for energ will continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 35 percent from 2010 to 2040. This demand increase is expected to b concentrated in developing countries (i.e., those that are not member nations of the Organisation for Economic Co-operation and Development).

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

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 40 percent from 2010 to 2040. The growth in transportation energ demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Nearly all the world’s transportation fleets will continue to ru on liquid fuels, which are abundant, widely available, easy to transport, and provide a large quantity of energy in small volumes.

Demand for electricity around the world is likely to increase approximately 85 percent by 2040, led by growth in developing countries. Consistent with this projection, power generatic is expected to remain the largest and fastest-growing major segment of global energy demand. Meeting the expected growth in power demand will require a diverse set of energy source Natural gas demand is likely to grow most significantly and become the leading source of generated electricity by 2040, reflecting the efficiency of gas-fired power plants. Today, coal ha the largest fuel share in the power sector, but its share is likely to decline significantly by 2040 as policies are gradually adopted to reduce environmental impacts including those related t local air quality and greenhouse gas emissions. Nuclear power and renewables, led by hydropower and wind, are also expected to grow significantly over the period.

Liquid fuels provide the largest share of global energy supplies today due to their broad-based availability, affordability and ease of transportation, distribution and storage to mee consumer needs. By 2040, global demand for liquid fuels is expected to grow to approximately 115 million barrels of oil-equivalent per day, an increase of almost 30 percent from 201 Globally, crude production from traditional conventional sources will likely decrease slightly through 2040, with significant development activity mostly offsetting natural declines fro these fields. However, this decrease is expected to be more than offset by rising production from a variety of emerging supply sources – including tight oil, deepwater, oil sands, natura gas liquids and biofuels. The world's resource base is sufficient to meet projected demand through 2040 as technology advances continue to expand the availability of economic suppl options. However, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel, suitable for a wide variety of applications, and is expected to be the fastest growing major fuel source through 2040. Global demand is expected to ris about 65 percent from 2010 to 2040, with about half of that increase in the Asia Pacific region. Helping meet these needs will be significant growth in supplies of unconventional gas – th natural gas found in shale and other rock formations that was once considered uneconomic to produce. About two-thirds of the growth in natural gas supplies is expected to be fro unconventional sources, which will account for close to 35 percent of global gas supplies by 2040. The worldwide liquefied natural gas (LNG) market is expected to more than triple b 2040, stimulated by growing natural gas demand.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 204 Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas in the 2025-2030 timeframe. The share of natural gas is expected to excee 25 percent by 2040, while the share of coal falls to less than 20 percent. Nuclear power is projected to grow significantly, as many nations expand nuclear capacity to address risin electricity needs as well as energy security and environmental issues. Total renewable energy is likely to reach about 15 percent of total energy by 2040, with biomass, hydro an geothermal contributing a combined share of more than 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase close to 450 percent from 2010 to 204 when they will be approaching 4 percent of world energy.

The Corporation anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from reserve increases in previously discovere fields. Technology will underpin these increases. The cost to develop and supply these resources will be significant. According to the International Energy Agency, the investment require to meet total oil and gas energy needs worldwide over the period 2014-2040 will be about $28 trillion (measured in 2013 dollars) or more than $1 trillion per year on average.

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

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

Upstream

ExxonMobil continues to maintain a diverse portfolio of exploration and development opportunities, which enables the Corporation to be selective, maximizing shareholder value ar mitigating political and technical risks. ExxonMobil's fundamental Upstream business strategies guide our global exploration, development, production, and gas and power marketin activities. These strategies include capturing material and accretive opportunities to continually high-grade the resource portfolio, exercising a disciplined approach to investing and co management, developing and applying high-impact technologies, pursuing productivity and efficiency gains, growing profitable oil and gas production, and capitalizing on growin natural gas and power markets. These strategies are underpinned by a relentless focus on operational excellence, commitment to innovative technologies, development of our employee and investment in the communities within which we operate.

As future development projects and drilling activities bring new production online, the Corporation expects a shift in the geographic mix and in the type of opportunities from whic volumes are produced. Oil equivalent production from North America is expected to increase over the next several years based on current capital activity plans, contributing over a third c total production. Further, the proportion of our global production from resource types utilizing specialized technologies such as arctic, deepwater, and unconventional drilling an production systems, as well as LNG, is also expected to grow, becoming a slight majority of production in the next few years. We do not anticipate that the expected change in th geographic mix of production volumes, and in the types of opportunities from which volumes will be produced, will have a material impact on the nature and the extent of the risks disclosed in Item 1A. Risk Factors, or result in a material change in our level of unit operating expenses.

The Corporation's overall volume capacity outlook, based on projects coming onstream as anticipated, is for production capacity to grow over the next few years. However, actua volumes will vary from year to year due to the timing of individual project start-ups and other capital activities, operational outages, reservoir performance, performance of enhanced c recovery projects, regulatory changes, the impact of fiscal and commercial terms, asset sales, weather events, price effects on production sharing contracts and other factors described Item 1A. Risk Factors. Enhanced oil recovery projects extract hydrocarbons from reservoirs in excess of that which may be produced through primary recovery, i.e., through pressu depletion or natural aquifer support. They include the injection of water, gases or chemicals into a reservoir to produce hydrocarbons otherwise unobtainable.

The markets for crude oil and natural gas have a history of significant price volatility. After some years of relatively stable prices, the end of 2014 saw crude prices drop to levels no seen since 2009. ExxonMobil believes prices over the long term will continue to be driven by market supply and demand, with the demand side largely being a function of global econom growth. To manage the risks associated with price, ExxonMobil evaluates annual plans and all investments across a wide range of price scenarios. The Corporation's assessment is that it operations will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment, cost management, and asset enhancement programs.

Downstream

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

ExxonMobil has an ownership interest in 30 refineries, located in 17 countries, with distillation capacity of 5.2 million barrels per day and lubricant basestock manufacturing capacit of 131 thousand barrels per day. ExxonMobil's fuels and lubes marketing businesses have significant global reach, with multiple channels to market serving a diverse customer base. Ou portfolio of world-renowned brands includes *Exxon*, *Mobil*, *Esso* and *Mobil 1*.

The downstream industry environment remains challenging. Demand weakness and overcapacity in the refining sector will continue to increase competitive pressure. In the near terr we see variability in refining margins, with some regions seeing weaker margins as new capacity additions outpace global demand. In North America, lower raw material and energy co driven by increasing crude oil and natural gas production has strengthened refining margins over the past few years.

Refining margins are largely driven by differences in commodity prices and are a function of the difference between what a refinery pays for its raw materials (primarily crude oil) ar the market prices for the range of products produced (primarily gasoline, heating oil, diesel oil, jet fuel and fuel oil). Crude oil and many products are widely traded with published price including those quoted on multiple exchanges around the world (e.g., New York Mercantile Exchange and Intercontinental Exchange). Prices for these commodities are determined by th global marketplace and are influenced by many factors, including global and regional supply/demand balances, inventory levels, industry refinery operations, import/export balance currency fluctuations, seasonal demand, weather and political climate.

ExxonMobil's long-term outlook is that industry refining margins will remain subject to intense competition as, in the near term, new capacity additions outpace the growth in glob demand. Additionally, as described in more detail in Item 1A. Risk Factors, proposed carbon policy and other climate-related regulations in many countries, as well as the continue growth in biofuels mandates, could have negative impacts on the refining business. ExxonMobil's integration across the value chain, from refining to marketing, enhances overall value i both fuels and lubricants businesses.

In the retail fuels marketing business, competition has caused inflation-adjusted margins to decline. In 2014, ExxonMobil expanded its branded retail site network in the U.S. ar progressed the multi-year transition of the direct served (i.e., dealer, company-operated) retail network in portions of Europe to a more capital-efficient branded distributor mode ExxonMobil is increasing investment in its fuels brands and developing multiple programs that will enhance the value of its consumer retail offer. The company's lubricants busines continues to grow, leveraging world-class brands and integration with industry-leading basestock refining capability. ExxonMobil remains a market leader in the high-value syntheti lubricants sector where competition is increasing.

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. When investing in th Downstream, ExxonMobil remains focused on selective and resilient projects. These investments capitalize on the Corporation's world-class scale and integration, demonstrated efficiency, advanced technology and respected brands, enabling ExxonMobil take advantage of attractive emerging growth opportunities around the globe. In 2014, the company commissioned the clean fuels project at the joint Saudi Aramco and ExxonMob SAMREF Refinery in Yanbu, Saudi Arabia, to produce low sulfur gasoline and ultra-low sulfur diesel. Construction started on a new delayed coker unit at the refinery in Antwerp Belgium, to upgrade low-value bunker fuel into high-value diesel products. The company also completed an expansion of lube basestock capacity at the refinery in Singapore, and neare completion on a lube basestock expansion in Baytown, Texas. A finished lubricant plant expansion in Tianjin, China, was completed and additional lubricant plant expansions in China Singapore, Finland, and the U.S. are underway to support demand growth for finished lubricants and greases in key markets.

Chemical

Worldwide petrochemical demand continued to improve in 2014, led by growing demand from Asia Pacific manufacturers of industrial and consumer products. North America continue to benefit from abundant supplies of natural gas and gas liquids, providing both low-cost feedstock and energy savings. Specialty product margins declined reflecting significant ne industry capacity.

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

In 2014, ExxonMobil began construction of a major expansion at our Texas facilities, including a new world-scale ethane cracker and polyethylene lines, to capitalize on low-co feedstock and energy supplies in North America and meet rapidly growing demand for premium polymers. Construction of new halobutyl rubber and hydrocarbon resin units also starte in Singapore to further extend our specialty product capacity in Asia. At the joint venture facility in Al-Jubail, Saudi Arabia, construction continued on the specialty elastomers project tha is expected to start-up in 2015.

REVIEW OF 2014 AND 2013 RESULTS

	2014	2013	2012
		(millions of dollars)	
Earnings (U.S. GAAP)			
Net income attributable to ExxonMobil (U.S. GAAP)	32,520	32,580	44,88

Upstream

	2014	2013	2012
		(millions of dollars)	
Upstream			
United States	5,197	4,191	3,92
Non-U.S.	22,351	22,650	25,97
Total	27,548	26,841	29,89

2014

Upstream earnings were $27,548 million, up $707 million from 2013. Lower prices decreased earnings by $2.0 billion. Favorable volume effects increased earnings by $510 million. A other items, primarily asset sales and favorable U.S. deferred income tax items, increased earnings by $2.2 billion. On an oil-equivalent basis, production of 4.0 million barrels per day wa down 4.9 percent compared to 2013. Excluding the impact of the expiry of the Abu Dhabi onshore concession, production decreased 1.7 percent. Liquids production of 2.1 million barre per day decreased 91,000 barrels per day compared to 2013. The Abu Dhabi onshore concession expiry reduced volumes by 135,000 barrels per day. Excluding this impact, liquic production was up 2 percent, driven by project ramp-up and work programs. Natural gas production of 11.1 billion cubic feet per day decreased 691 million cubic feet per day from 201 as expected U.S. field decline and lower European demand were partially offset by project ramp-up and work programs. Earnings from U.S. Upstream operations were $5,197 million, u $1,006 million from 2013. Earnings outside the U.S. were $22,351 million, down $299 million from the prior year.

2013

Upstream earnings were $26,841 million, down $3,054 million from 2012. Higher gas realizations, partially offset by lower liquids realizations, increased earnings by $390 millior Production volume and mix effects decreased earnings by $910 million. All other items, including lower net gains from asset sales, mainly in Angola, and higher expenses, reduce earnings by $2.5 billion. On an oil-equivalent basis, production was down 1.5 percent compared to 2012. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, production was essentially flat. Liquids production of 2.2 million barrels per day increased 17,000 barrels per day compared with 201 Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production was up 1.6 percent, as project ramp-up and lower downtime were partially offset b field decline. Natural gas production of 11.8 billion cubic feet per day decreased 486 million cubic feet per day from 2012. Excluding the impacts of entitlement volumes ar divestments, natural gas production was down 1.5 percent, as field decline was partially offset by higher demand, lower downtime, and project ramp-up. Earnings from U.S. Upstrea operations for 2013 were $4,191 million, up $266 million from 2012. Earnings outside the U.S. were $22,650 million, down $3,320 million from the prior year.

Upstream Additional Information

	2014	2013
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production)*(1)*		
Prior year	4,175	4,239
Entitlements - Net Interest	(4)	(38
Entitlements - Price / Spend / Other	(43)	(9
Quotas	-	3
Divestments	(31)	(26
United Arab Emirates Onshore Concession Expiry	(135)	-
Growth / Other	7	6
Current Year	3,969	4,175

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

Listed below are descriptions of ExxonMobil's volumes reconciliation factors which are provided to facilitate understanding of the terms.

Entitlements - Net Interest are changes to ExxonMobil's share of production volumes caused by non-operational changes to volume-determining factors. These factors consist of n interest changes specified in Production Sharing Contracts (PSCs) which typically occur when cumulative investment returns or production volumes achieve defined thresholds, changes equity upon achieving pay-out in partner investment carry situations, equity redeterminations as specified in venture agreements, or as a result of the termination or expiry of a concessio Once a net interest change has occurred, it typically will not be reversed by subsequent events, such as lower crude oil prices.

Entitlements - Price, Spend and Other are changes to ExxonMobil's share of production volumes resulting from temporary changes to non-operational volume-determining factor These factors include changes in oil and gas prices or spending levels from one period to another. According to the terms of contractual arrangements or government royalty regimes, pric or spending variability can increase or decrease royalty burdens and/or volumes attributable to ExxonMobil. For example, at higher prices, fewer barrels are required for ExxonMobil recover its costs. These effects generally vary from period to period with field spending patterns or market prices for oil and natural gas. Such factors can also include other tempora changes in net interest as dictated by specific provisions in production agreements.

Quotas are changes in ExxonMobil's allowable production arising from production constraints imposed by countries which are members of the Organization of the Petroleu Exporting Countries (OPEC). Volumes reported in this category would have been readily producible in the absence of the quota.

Divestments are reductions in ExxonMobil's production arising from commercial arrangements to fully or partially reduce equity in a field or asset in exchange for financial or oth economic consideration.

Growth and Other factors comprise all other operational and non-operational factors not covered by the above definitions that may affect volumes attributable to ExxonMobil. Su factors include, but are not limited to, production enhancements from project and work program activities, acquisitions including additions from asset exchanges, downtime, mark demand, natural field decline, and any fiscal or commercial terms that do not affect entitlements.

Downstream

	2014	2013	2012
		(millions of dollars)	
Downstream			
United States	1,618	2,199	3,57
Non-U.S.	1,427	1,250	9,61
Total	3,045	3,449	13,19

2014

Downstream earnings of $3,045 million decreased $404 million from 2013. Lower margins decreased earnings by $230 million. Volume and mix effects increased earnings b $480 million. All other items, primarily unfavorable foreign exchange and tax impacts, partially offset by lower expenses, decreased earnings by $650 million. Petroleum product sales c 5.9 million barrels per day were in line with 2013. U.S. Downstream earnings were $1,618 million, a decrease of $581 million from 2013. Non-U.S. Downstream earnings were $1,42 million, up $177 million from the prior year.

2013

Downstream earnings of $3,449 million decreased $9,741 million from 2012 driven by the absence of the $5.3 billion gain associated with the Japan restructuring. Lower margins, main refining, decreased earnings by $2.9 billion. Volume and mix effects decreased earnings by $310 million. All other items, including higher operating expenses, unfavorable foreig exchange impacts, and lower divestments, decreased earnings by $1.2 billion. Petroleum product sales of 5.9 million barrels per day decreased 287,000 barrels per day from 2012. U. Downstream earnings were $2,199 million, down $1,376 million from 2012. Non-U.S. Downstream earnings were $1,250 million, a decrease of $8,365 million from the prior year.

Chemical

	2014	2013	2012
		(millions of dollars)	
Chemical			
United States	2,804	2,755	2,22
Non-U.S.	1,511	1,073	1,67
Total	4,315	3,828	3,89

2014

Chemical earnings of $4,315 million increased $487 million from 2013. Higher commodity-driven margins increased earnings by $520 million, while volume and mix effects increase earnings by $100 million. All other items, primarily higher planned expenses, decreased earnings by $130 million. Prime product sales of 24.2 million metric tons were up 172,000 tor from 2013, driven by increased Singapore production. U.S. Chemical earnings were $2,804 million, up $49 million from 2013. Non-U.S. Chemical earnings were $1,511 millio $438 million higher than the prior year.

2013

Chemical earnings of $3,828 million were $70 million lower than 2012. The absence of the gain associated with the Japan restructuring decreased earnings by $630 million. High margins increased earnings by $480 million, while volume and mix effects increased earnings by $80 million. Prime product sales of 24.1 million metric tons were down 94,000 tons fro 2012. U.S. Chemical earnings were $2,755 million, up $535 million from 2012. Non-U.S. Chemical earnings were $1,073 million, $605 million lower than the prior year.

Corporate and Financing

	2014	2013	2012
		(millions of dollars)	
Corporate and financing	(2,388)	(1,538)	(2,10

2014

Corporate and financing expenses were $2,388 million in 2014, up $850 million from 2013 due primarily to tax-related items.

2013

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

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2014	2013	2012
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	45,116	44,914	56,170
Investing activities	(26,975)	(34,201)	(25,601
Financing activities	(17,888)	(15,476)	(33,868
Effect of exchange rate changes	(281)	(175)	217
Increase/(decrease) in cash and cash equivalents	(28)	(4,938)	(3,082
		(December 31)	
Cash and cash equivalents	4,616	4,644	9,582
Cash and cash equivalents - restricted	42	269	341
Total cash and cash equivalents	4,658	4,913	9,923

Total cash and cash equivalents were $4.7 billion at the end of 2014, $0.3 billion lower than the prior year. The major sources of funds in 2014 were net income including noncontrollin interests of $33.6 billion, the adjustment for the noncash provision of $17.3 billion for depreciation and depletion, a net debt increase of $7.0 billion and collection of advances of $3 billion. The major uses of funds included spending for additions to property, plant and equipment of $33.0 billion, the purchase of shares of ExxonMobil stock of $13.2 billion, dividenc to shareholders of $11.6 billion and a change in working capital, excluding cash and debt, of $4.9 billion. Included in total cash and cash equivalents at year-end 2014 was $42 million restricted cash.

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

The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirement supplemented by long-term and short-term debt. On December 31, 2014, the Corporation had unused committed short-term lines of credit of $6.3 billion and unused committed long-ter lines of credit of $0.5 billion. Cash that may be temporarily available as surplus to the Corporation's immediate needs is carefully managed through counterparty quality and investme guidelines to ensure it is secure and readily available to meet the Corporation's cash requirements and to optimize returns.

To support cash flows in future periods the Corporation will need to continually find and develop new fields, and continue to develop and apply new technologies and recove processes to existing fields, in order to maintain or increase production. After a period of production at plateau rates, it is the nature of oil and gas fields eventually to produce at declinin rates for the remainder of their economic life. Averaged over all the Corporation's existing oil and gas fields and without new projects, ExxonMobil's production is expected to decline a an average of approximately 3 percent per year over the next few years. Decline rates can vary widely by individual field due to a number of factors, including, but not limited to, the typ of reservoir, fluid properties, recovery mechanisms, work activity, and age of the field. Furthermore, the Corporation's net interest in production for individual fields can vary with pric and the impact of fiscal and commercial terms.

The Corporation has long been successful at offsetting the effects of natural field decline through disciplined investments in quality opportunities and project execution. Over the la decade, this has resulted in net annual additions to proved reserves that have exceeded the amount produced. Projects are in progress or planned to increase production capacity. Howeve these volume increases are subject to a variety of risks including project start-up timing, operational outages, reservoir performance, the impact of fiscal and commercial terms, crude c and natural gas prices, weather events, and regulatory changes. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please refer to Item 1A. Ris 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 2014 were $38.5 billion, reflecting th Corporation's continued active investment program. The Corporation anticipates an average investment profile of about $34 billion per year for the next few years. Actual spending coul vary depending on the progress of individual projects and property acquisitions. The Corporation has a large and diverse portfolio of development projects and exploration opportunities, which helps mitigate the overall political and technical risks of the Corporation's Upstream segment and associated cash flov Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impa on the Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments. The purchase and sale of oil and gas properties have not had significant impact on the amount or timing of cash flows from operating activities.

Cash Flow from Operating Activities

2014

Cash provided by operating activities totaled $45.1 billion in 2014, $0.2 billion higher than 2013. The major source of funds was net income including noncontrolling interests of $33 billion, an increase of $0.2 billion. The noncash provision for depreciation and depletion was $17.3 billion, up $0.1 billion from the prior year. The adjustment for net gains on asset sal was $3.2 billion compared to an adjustment of $1.8 billion in 2013. Changes in operational working capital, excluding cash and debt, decreased cash in 2014 by $4.9 billion.

2013

Cash provided by operating activities totaled $44.9 billion in 2013, $11.3 billion lower than 2012. The major source of funds was net income including noncontrolling interests of $33 billion, a decrease of $14.2 billion. The noncash provision of $17.2 billion for depreciation and depletion was higher than 2012. The adjustment for net gains on asset sales was $1.8 billic compared to an adjustment of $13.0 billion in 2012. Changes in operational working capital, excluding cash and debt, decreased cash in 2013 by $4.7 billion.

Cash Flow from Investing Activities

2014

Cash used in investment activities netted to $27.0 billion in 2014, $7.2 billion lower than 2013. Spending for property, plant and equipment of $33.0 billion decreased $0.7 billion fro 2013. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $4.0 billion compared to $2.7 billion in 2013. Addition investments and advances were $2.8 billion lower in 2014, while collection of advances was $2.2 billion higher in 2014.

2013

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

Cash Flow from Financing Activities

2014

Cash used in financing activities was $17.9 billion in 2014, $2.4 billion higher than 2013. Dividend payments on common shares increased to $2.70 per share from $2.46 per share a totaled $11.6 billion, a pay-out of 36 percent of net income. During the first quarter of 2014, the Corporation issued $5.5 billion of long-term debt. Total debt increased $6.4 billion $29.1 billion at year-end.

ExxonMobil share of equity increased $0.4 billion to $174.4 billion. The addition to equity for earnings was $32.5 billion. This was offset by reductions for distributions to ExxonMob shareholders of $23.6 billion, composed of $11.6 billion in dividends and $12.0 billion of share purchases of ExxonMobil stock to reduce shares outstanding. Foreign exchange translati effects of $5.1 billion for the stronger U.S. currency and a $3.1 billion change in the funded status of the postretirement benefits reserves also reduced equity.

During 2014, Exxon Mobil Corporation purchased 136 million shares of its common stock for the treasury at a gross cost of $13.2 billion. These purchases were to reduce the numb of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 3.1 percent from 4,335 million to 4,2 million at the end of 2014. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time witho prior notice.

2013

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

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

During 2013, Exxon Mobil Corporation purchased 177 million shares of its common stock for the treasury at a gross cost of $16.0 billion. These purchases were to reduce the numb of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 3.7 percent from 4,502 million to 4,33 million at the end of 2013. Purchases were made in both the open market and through negotiated transactions.

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2014. It combines data from the Consolidated Balanc Sheet and from individual notes to the Consolidated Financial Statements.

		Payments Due by Period			
Commitments	**Note Reference Number**	**2015**	**2016-2019**	**2020 and Beyond**	**Total**
			(millions of dollars)		
Long-term debt *(1)*	14	-	6,755	4,898	11,65
– Due in one year *(2)*	6	770	-	-	77
Asset retirement obligations *(3)*	9	1,055	2,763	9,606	13,42
Pension and other postretirement obligations *(4)*	17	1,524	4,346	20,664	26,53
Operating leases *(5)*	11	2,034	2,883	1,296	6,21
Unconditional purchase obligations *(6)*	16	150	608	337	1,09
Take-or-pay obligations *(7)*		2,973	10,671	14,065	27,70
Firm capital commitments *(8)*		16,065	7,893	1,643	25,60

This table excludes commodity purchase obligations (volumetric commitments but no fixed or minimum price) which are resold shortly after purchase, either in an active, highly liqu market or under long-term, unconditional sales contracts with similar pricing terms. Examples include long-term, noncancelable LNG and natural gas purchase commitments ar commitments to purchase refinery products at market prices. Inclusion of such commitments would not be meaningful in assessing liquidity and cash flow, because these purchases will b offset in the same periods by cash received from the related sales transactions. The table also excludes unrecognized tax benefits totaling $9.0 billion as of December 31, 2014, because th Corporation is unable to make reasonably reliable estimates of the timing of cash settlements with the respective taxing authorities. Further details on the unrecognized tax benefits can b found in Note 19, Income, Sales-Based and Other Taxes.

Notes:

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

(2) The amount due in one year is included in notes and loans payable of $17,468 million.

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

(4) The amount by which the benefit obligations exceeded the fair value of fund assets for certain U.S. and non-U.S. pension and other postretirement plans at year end. The payments period include expected contributions to funded pension plans in 2015 and estimated benefit payments for unfunded plans in all years.

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

(6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable or cancelable only under certain conditions, and that third parties have use secure financing for the facilities that will provide the contracted goods or services. The undiscounted obligations of $1,095 million mainly pertain to pipeline throughput agreem and include $433 million of obligations to equity companies.

(7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than UPOs. The undiscounted obligations of $27,709 million mainly pertai pipeline, manufacturing supply and terminal agreements.

(8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately $25.6 billion. These commitments were primarily associated with Upstr projects outside the U.S., of which $13.9 billion was associated with projects in Africa, Canada, Australia, United Arab Emirates, Malaysia and Kazakhstan. The Corporation exp to fund the majority of these projects with internally generated funds, supplemented by long-term and short-term debt.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2014, for guarantees relating to notes, loans and performance under contracts (No 16). Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposur These guarantees are not reasonably likely to have a material effect on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operation liquidity, capital expenditures or capital resources.

Financial Strength

On December 31, 2014, the Corporation's unused short-term committed lines of credit totaled approximately $6.3 billion (Note 6) and unused long-term committed lines of credit totale approximately $0.5 billion (Note 14). The table below shows the Corporation's fixed-charge coverage and consolidated debt-to-capital ratios. The data demonstrate the Corporation creditworthiness.

	2014	2013	201
Fixed-charge coverage ratio (times)	46.9	55.7	62.4
Debt to capital (percent)	13.9	11.2	6.[illegible]
Net debt to capital (percent)	11.9	9.1	1.[illegible]

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

Litigation and Other Contingencies

As discussed in Note 16, a variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. Based on a consideration o all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a material adverse effect upo the Corporation's operations, financial condition, or financial statements taken as a whole. There are no events or uncertainties beyond those already included in reported financi information that would indicate a material change in future operating results or financial condition. Refer to Note 16 for additional information on legal proceedings and oth contingencies.

CAPITAL AND EXPLORATION EXPENDITURES

	2014			2013		
	U.S.	**Non-U.S.**	**Total**	**U.S.**	**Non-U.S.**	**Total**
			(millions of dollars)			
Upstream *(1)*	9,401	23,326	32,727	9,145	29,086	38,23
Downstream	1,310	1,724	3,034	951	1,462	2,41
Chemical	1,690	1,051	2,741	963	869	1,83
Other	35	-	35	13	-	1
Total	12,436	26,101	38,537	11,072	31,417	42,48

(1) Exploration expenses included.

Capital and exploration expenditures in 2014 were $38.5 billion, down 9 percent from 2013 due primarily to the absence of the $3.1 billion Celtic Exploration Ltd. acquisition in 2013. Th Corporation anticipates an average investment profile of about $34 billion per year for the next few years. Actual spending could vary depending on the progress of individual projects an property acquisitions.

Upstream spending of $32.7 billion in 2014 was down 14 percent from 2013, reflecting the absence of $4.2 billion of property acquisition costs in 2013. Investments in 2014 include projects in the U.S. Gulf of Mexico, U.S. onshore drilling, exploration in Russia and continued progress on world-class projects in Canada and Australia. The majority of expenditures ar on development projects, which typically take two to four years from the time of recording proved undeveloped reserves to the start of production. The percentage of proved develope reserves was 65 percent of total proved reserves at year-end 2014, and has been over 60 percent for the last ten years, indicating that proved reserves are consistently moved fro undeveloped to developed status.

Capital investments in the Downstream totaled $3.0 billion in 2014, an increase of $0.6 billion from 2013, mainly reflecting higher spending on crude oil transportation infrastructur The Chemical capital expenditures of $2.7 billion increased $0.9 billion from 2013 with higher investments in the U.S.

TAXES

	2014	**2013**	**2012**
		(millions of dollars)	
Income taxes	18,015	24,263	31,04
Effective income tax rate	*41%*	*48%*	*44*
Sales-based taxes	29,342	30,589	32,40
All other taxes and duties	35,515	36,396	38,85
Total	82,872	91,248	102,31

2014

Income, sales-based and all other taxes and duties totaled $82.9 billion in 2014, a decrease of $8.4 billion or 9 percent from 2013. Income tax expense, both current and deferred, wa $18.0 billion, $6.2 billion lower than 2013, as a result of a lower effective tax rate. The effective tax rate was 41 percent compared to 48 percent in the prior year due primarily to impac related to the Corporation's asset management program and favorable U.S. deferred tax items. Sales-based and all other taxes and duties of $64.9 billion in 2014 decreased $2.1 billion.

2013

Income, sales-based and all other taxes and duties totaled $91.2 billion in 2013, a decrease of $11.1 billion or 11 percent from 2012. Income tax expense, both current and deferred, wa $24.3 billion, $6.8 billion lower than 2012, with the impact of lower earnings partially offset by the higher effective tax rate. The effective tax rate was 48 percent compared to 44 perce in the prior year due to the absence of favorable tax impacts on divestments. Sales-based and all other taxes and duties of $67.0 billion in 2013 decreased $4.3 billion reflecting the 201 Japan restructuring.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2014	2013
	(millions of dollars)	
Capital expenditures	2,666	2,47
Other expenditures	3,522	3,53
Total	6,188	6,01

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significa investment in refining infrastructure and technology to manufacture clean fuels, as well as projects to monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions, ar expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2014 worldwide environmental expenditur for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were about $6.2 billion. The total cost for such activities is expected t remain in this range in 2015 and 2016 (with capital expenditures approximately 40 percent of the total).

Environmental Liabilities

The Corporation accrues environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for probable environmental remediation obligations at various sites, including multiparty sit where the U.S. Environmental Protection Agency has identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies these multiparty sites could mitigate ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil's operation or financial condition. Consolidated company provisions made in 2014 for environmental liabilities were $780 million ($321 million in 2013) and the balance sheet reflects accumulate liabilities of $1,066 million as of December 31, 2014, and $773 million as of December 31, 2013.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2014	2013	201
Crude oil and NGL ($/barrel)	87.42	97.48	100.2
Natural gas ($/kcf)	4.68	4.60	3.9

(1) Consolidated subsidiaries.

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstrear Downstream and Chemical operations have varied. In the Upstream, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $350 million annu after-tax effect on Upstream consolidated plus equity company earnings. Similarly, a $0.10 per kcf change in the worldwide average gas realization would have approximately a $17 million annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment will be dependent on the pric movements of individual types of crude oil, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volume Accordingly, changes in benchmark prices for crude oil and natural gas only provide broad indicators of changes in the earnings experienced in any particular period.

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

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

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where such sales take place, they are the result efficiencies and competitive advantages of integrated refinery/chemical complexes. Additionally, intersegment sales are at market-based prices. The products bought and sold betwee segments can also be acquired in worldwide markets that have substantial liquidity, capacity and transportation capabilities. About 35 percent of the Corporation's intersegment sale represent Upstream production sold to the Downstream. Other intersegment sales include those between refineries and chemical plants related to raw materials, feedstocks and finishe products.

Although price levels of crude oil and natural gas may rise or fall significantly over the short to medium term due to political events, OPEC actions and other factors, industr economics over the long term will continue to be driven by market supply and demand. Accordingly, the Corporation evaluates the viability of all of its investments over a broad range c future prices. The Corporation's assessment is that its operations will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment and ass management programs.

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

Risk Management

The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation' enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivative instruments to mitigate the impact c such changes. With respect to derivatives activities, the Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations c liquidity as a result of the derivatives described in Note 13. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivativ with leveraged features. Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the qualit of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

The Corporation is exposed to changes in interest rates, primarily on its short-term debt and the portion of long-term debt that carries floating interest rates. The impact of a 100-basi point change in interest rates affecting the Corporation's debt would not be material to earnings, cash flow or fair value. The Corporation has access to significant capacity of long-ter and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt. Some joint-ventur partners are dependent on the credit markets, and their funding ability may impact the development pace of joint-venture projects.

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

Inflation and Other Uncertainties

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

RECENTLY ISSUED ACCOUNTING STANDARDS

In May 2014, the Financial Accounting Standards Board issued a new standard, *Revenue from Contracts with Customers.* The standard establishes a single revenue recognition model fo all contracts with customers, eliminates industry specific requirements, and expands disclosure requirements. The standard is required to be adopted beginning January 1, 201 ExxonMobil is evaluating the standard and its effect on the Corporation's financial statements.

CRITICAL ACCOUNTING ESTIMATES

The Corporation's accounting and financial reporting fairly reflect its straightforward business model involving the extracting, refining and marketing of hydrocarbons and hydrocarbor based products. The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates and judgmer that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The Corporation's accounting policies are summarized i Note 1.

Oil and Gas Reserves

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

Oil and gas reserves include both proved and unproved reserves. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering dat can be estimated with reasonable certainty to be economically producible. Unproved reserves are those with less than reasonable certainty of recoverability and include probable reserve Probable reserves are reserves that are more likely to be recovered than not.

The estimation of proved reserves is an ongoing process based on rigorous technical evaluations, commercial and market assessment, and detailed analysis of well information such a flow rates and reservoir pressure declines. The estimation of proved reserves is controlled by the Corporation through long-standing approval guidelines. Reserve changes are made with a well-established, disciplined process driven by senior level geoscience and engineering professionals, assisted by the Reserves Technical Oversight group which has significant technica experience, culminating in reviews with and approval by senior management. Notably, the Corporation does not use specific quantitative reserve targets to determine compensation. Ke features of the reserve estimation process are covered in Disclosure of Reserves in Item 2.

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

Proved reserves can be further subdivided into developed and undeveloped reserves. The percentage of proved developed reserves was 65 percent of total proved reserves at year-en 2014 (including both consolidated and equity company reserves), and has been over 60 percent for the last ten years, indicating that proved reserves are consistently moved fro undeveloped to developed status.

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

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

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

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

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance success and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based development risk and average holding period.

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses assist the Corporation in assessing whether th carrying amounts of any of its assets may not be recoverable. In addition to estimating oil and gas reserve volumes in conducting these analyses, it is also necessary to estimate future c and gas prices. Potential trigger events for impairment evaluation include a significant decrease in current and projected reserve volumes, an accumulation of project costs significantly excess of the amount originally expected, and current period operating losses combined with a history and forecast of operating or cash flow losses.

In general, the Corporation does not view temporarily low prices or margins as a trigger event for conducting the impairment tests. The markets for crude oil and natural gas have history of significant price volatility. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. O the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies als have an impact on world oil supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus demand will determine industry pric over the long term, and these cannot be accurately predicted.

Accordingly, any impairment tests that the Corporation performs make use of the Corporation's price assumptions developed in the annual planning and budgeting process for the cruc oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. Volumes are based on field productio profiles, which are updated annually. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

Supplemental information regarding oil and gas results of operations, capitalized costs and reserves is provided following the notes to consolidated financial statements. Future pric used for any impairment tests will vary from the ones used in the supplemental oil and gas disclosure and could be lower or higher for any given year.

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the asse are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligatio technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations are disclosed in Note 9 to the financi statements.

Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and th Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged t expense. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in Note 10 to the financial statements.

Consolidations

The Consolidated Financial Statements include the accounts of those subsidiaries that the Corporation controls. They also include the Corporation's share of the undivided interest i certain upstream assets, liabilities, revenues and expenses. Amounts representing the Corporation's interest in the underlying net assets of other significant entities that it does not contro but over which it exercises significant influence, are accounted for using the equity method of accounting.

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

Pension Benefits

The Corporation and its affiliates sponsor about 100 defined benefit (pension) plans in over 40 countries. The Pension and Other Postretirement Benefits footnote (Note 17) provide details on pension obligations, fund assets and pension expense.

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

For funded plans, including those in the U.S., pension obligations are financed in advance through segregated assets or insurance arrangements. These plans are managed in complianc with the requirements of governmental authorities and meet or exceed required funding levels as measured by relevant actuarial and government standards at the mandated measureme dates. In determining liabilities and required contributions, these standards often require approaches and assumptions that differ from those used for accounting purposes.

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

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations and the lon term rate for future salary increases. Pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted as appropriate to refle changes in market rates and outlook. The long-term expected earnings rate on U.S. pension plan assets in 2014 was 7.25 percent. The 10-year and 20-year actual returns on U.S. pensio plan assets were 7 percent and 10 percent, respectively. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumptio for each pension fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated a the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the long-term rate o return on assets would increase annual pension expense by approximately $170 million before tax.

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

Litigation Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigation review including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The status of significant claims is summarized i Note 16.

The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable, and the amount can be reasonably estimated. These amounts a not reduced by amounts that may be recovered under insurance or claims against third parties, but undiscounted receivables from insurers or other third parties may be accrued separatel The Corporation revises such accruals in light of new information. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporatio discloses the nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of our litigation contingency disclosures, "significant" includes material matte as well as other items which management believes should be disclosed.

Management judgment is required related to contingent liabilities and the outcome of litigation because both are difficult to predict. However, the Corporation has been successful i defending litigation in the past. Payments have not had a material adverse effect on operations or financial condition. In the Corporation’s experience, large claims often do not result in large awards. Large awards are often reversed or substantiall reduced as a result of appeal or settlement.

Tax Contingencies

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

The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes th 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 measured at the largest amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken or expected to be taken in a income tax return and the amount recognized in the financial statements. The Corporation’s unrecognized tax benefits and a description of open tax years are summarized in Note 19.

Foreign Currency Translation

The method of translating the foreign currency financial statements of the Corporation’s international subsidiaries into U.S. dollars is prescribed by GAAP. Under these principles, it i necessary to select the functional currency of these subsidiaries. The functional currency is the currency of the primary economic environment in which the subsidiary operate Management selects the functional currency after evaluating this economic environment.

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation's Chief Executive Officer, Principal Financial Officer, and Principal Accounting Officer, is responsible for establishing and maintaining adequat internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criter established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, manageme concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2014.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as c December 31, 2014, as stated in their report included in the Financial Section of this report.

Rex W. Tillerson Chief Executive Officer	Andrew P. Swiger Senior Vice President (Principal Financial Officer)	David S. Rosenthal Vice President and Controller (Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Exxon Mobil Corporation:

In our opinion, the accompanying Consolidated Balance Sheets and the related Consolidated Statements of Income, Comprehensive Income, Changes in Equity and Cash Flows prese fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cas flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. Also in our opinio the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Corporation's management is responsible for thes financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in th accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Corporation's intern control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (Unite States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and wheth effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting th amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial stateme presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a materi weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedur as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 25, 2015

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2014	2013	2012
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*		394,105	420,836	451,50
Income from equity affiliates	7	13,323	13,927	15,01
Other income		4,511	3,492	14,16
Total revenues and other income		411,939	438,255	480,68
Costs and other deductions				
Crude oil and product purchases		225,972	244,156	263,53
Production and manufacturing expenses		40,859	40,525	38,52
Selling, general and administrative expenses		12,598	12,877	13,87
Depreciation and depletion		17,297	17,182	15,88
Exploration expenses, including dry holes		1,669	1,976	1,84
Interest expense		286	9	32
Sales-based taxes *(1)*	19	29,342	30,589	32,40
Other taxes and duties	19	32,286	33,230	35,55
Total costs and other deductions		360,309	380,544	401,95
Income before income taxes		51,630	57,711	78,72
Income taxes	19	18,015	24,263	31,04
Net income including noncontrolling interests		33,615	33,448	47,68
Net income attributable to noncontrolling interests		1,095	868	2,80
Net income attributable to ExxonMobil		32,520	32,580	44,88
Earnings per common share *(dollars)*	12	7.60	7.37	9.7
Earnings per common share - assuming dilution *(dollars)*	12	7.60	7.37	9.7

(1) Sales and other operating revenue includes sales-based taxes of $29,342 million for 2014, $30,589 million for 2013 and $32,409 million for 2012.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2014	2013	2012
		(millions of dollars)	
Net income including noncontrolling interests	33,615	33,448	47,681
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(5,847)	(3,620)	920
Adjustment for foreign exchange translation (gain)/loss included in net income	152	(23)	(4,352)
Postretirement benefits reserves adjustment (excluding amortization)	(4,262)	3,174	(3,574)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	1,111	1,820	2,395
Unrealized change in fair value of stock investments	(63)	-	-
Realized (gain)/loss from stock investments included in net income	3	-	-
Total other comprehensive income	(8,906)	1,351	(4,611)
Comprehensive income including noncontrolling interests	24,709	34,799	43,070
Comprehensive income attributable to noncontrolling interests	421	760	1,251
Comprehensive income attributable to ExxonMobil	24,288	34,039	41,819

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2014	Dec. 31 2013
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		4,616	4,644
Cash and cash equivalents - restricted		42	269
Notes and accounts receivable, less estimated doubtful amounts	6	28,009	33,152
Inventories			
Crude oil, products and merchandise	3	12,384	12,117
Materials and supplies		4,294	4,018
Other current assets		3,565	5,108
Total current assets		52,910	59,308
Investments, advances and long-term receivables	8	35,239	36,328
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	252,668	243,650
Other assets, including intangibles, net		8,676	7,522
Total assets		349,493	346,808
Liabilities			
Current liabilities			
Notes and loans payable	6	17,468	15,808
Accounts payable and accrued liabilities	6	42,227	48,085
Income taxes payable		4,938	7,831
Total current liabilities		64,633	71,724
Long-term debt	14	11,653	6,891
Postretirement benefits reserves	17	25,802	20,646
Deferred income tax liabilities	19	39,230	40,530
Long-term obligations to equity companies		5,325	4,742
Other long-term obligations		21,786	21,780
Total liabilities		168,429	166,313
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		10,792	10,077
Earnings reinvested		408,384	387,432
Accumulated other comprehensive income		(18,957)	(10,725)
Common stock held in treasury (3,818 million shares in 2014 and 3,684 million shares in 2013)		(225,820)	(212,781)
ExxonMobil share of equity		174,399	174,003
Noncontrolling interests		6,665	6,492
Total equity		181,064	180,495
Total liabilities and equity		349,493	346,808

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2014	2013	2012
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		33,615	33,448	47,681
Adjustments for noncash transactions				
Depreciation and depletion		17,297	17,182	15,888
Deferred income tax charges/(credits)		1,540	754	3,142
Postretirement benefits expense in excess of/(less than) net payments		524	2,291	(315)
Other long-term obligation provisions in excess of/(less than) payments		1,404	(2,566)	1,643
Dividends received greater than/(less than) equity in current earnings of equity companies		(358)	3	(1,157)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		3,118	(305)	(1,082)
- Inventories		(1,343)	(1,812)	(1,873)
- Other current assets		(68)	(105)	(42)
Increase/(reduction) - Accounts and other payables		(6,639)	(2,498)	3,624
Net (gain) on asset sales	5	(3,151)	(1,828)	(13,018)
All other items - net		(823)	350	1,679
Net cash provided by operating activities		45,116	44,914	56,170
Cash flows from investing activities				
Additions to property, plant and equipment		(32,952)	(33,669)	(34,271)
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	5	4,035	2,707	7,655
Decrease/(increase) in restricted cash and cash equivalents		227	72	63
Additional investments and advances		(1,631)	(4,435)	(598)
Collection of advances		3,346	1,124	1,550
Net cash used in investing activities		(26,975)	(34,201)	(25,601)
Cash flows from financing activities				
Additions to long-term debt		5,731	345	995
Reductions in long-term debt		(69)	(13)	(147)
Additions to short-term debt		-	16	958
Reductions in short-term debt		(745)	(756)	(4,488)
Additions/(reductions) in debt with three months or less maturity		2,049	12,012	(226)
Cash dividends to ExxonMobil shareholders		(11,568)	(10,875)	(10,092)
Cash dividends to noncontrolling interests		(248)	(304)	(327)
Changes in noncontrolling interests		-	(1)	204
Tax benefits related to stock-based awards		115	48	130
Common stock acquired		(13,183)	(15,998)	(21,068)
Common stock sold		30	50	193
Net cash used in financing activities		(17,888)	(15,476)	(33,868)
Effects of exchange rate changes on cash		(281)	(175)	217
Increase/(decrease) in cash and cash equivalents		(28)	(4,938)	(3,082)
Cash and cash equivalents at beginning of year		4,644	9,582	12,664
Cash and cash equivalents at end of year		4,616	4,644	9,582

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	Total Equity
				(millions of dollars)			
Balance as of December 31, 2011	9,512	330,939	(9,123)	(176,932)	154,396	6,348	160,74
Amortization of stock-based awards	806	-	-	-	806	-	80
Tax benefits related to stock-based awards	178	-	-	-	178	-	17
Other	(843)	-	-	-	(843)	(1,441)	(2,28
Net income for the year	-	44,880	-	-	44,880	2,801	47,68
Dividends - common shares	-	(10,092)	-	-	(10,092)	(327)	(10,41
Other comprehensive income	-	-	(3,061)	-	(3,061)	(1,550)	(4,61
Acquisitions, at cost	-	-	-	(21,068)	(21,068)	(34)	(21,10
Dispositions	-	-	-	667	667	-	66
Balance as of December 31, 2012	9,653	365,727	(12,184)	(197,333)	165,863	5,797	171,66
Amortization of stock-based awards	761	-	-	-	761	-	76
Tax benefits related to stock-based awards	162	-	-	-	162	-	16
Other	(499)	-	-	-	(499)	240	(25
Net income for the year	-	32,580	-	-	32,580	868	33,44
Dividends - common shares	-	(10,875)	-	-	(10,875)	(304)	(11,17
Other comprehensive income	-	-	1,459	-	1,459	(108)	1,35
Acquisitions, at cost	-	-	-	(15,998)	(15,998)	(1)	(15,99
Dispositions	-	-	-	550	550	-	55
Balance as of December 31, 2013	10,077	387,432	(10,725)	(212,781)	174,003	6,492	180,49
Amortization of stock-based awards	780	-	-	-	780	-	78
Tax benefits related to stock-based awards	49	-	-	-	49	-	4
Other	(114)	-	-	-	(114)	-	(11
Net income for the year	-	32,520	-	-	32,520	1,095	33,61
Dividends - common shares	-	(11,568)	-	-	(11,568)	(248)	(11,81
Other comprehensive income	-	-	(8,232)	-	(8,232)	(674)	(8,90
Acquisitions, at cost	-	-	-	(13,183)	(13,183)	-	(13,18
Dispositions	-	-	-	144	144	-	14
Balance as of December 31, 2014	10,792	408,384	(18,957)	(225,820)	174,399	6,665	181,06

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2011	8,019	(3,285)	4,734
Acquisitions	-	(244)	(244
Dispositions	-	12	12
Balance as of December 31, 2012	8,019	(3,517)	4,502
Acquisitions	-	(177)	(177
Dispositions	-	10	10
Balance as of December 31, 2013	8,019	(3,684)	4,335
Acquisitions	-	(136)	(136
Dispositions	-	2	2
Balance as of December 31, 2014	8,019	(3,818)	4,201

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reporte amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years' data has bee reclassified in certain cases to conform to the 2014 presentation basis.

1. Summary of Accounting Policies

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

Amounts representing the Corporation's interest in entities that it does not control, but over which it exercises significant influence, are included in "Investments, advances and long term receivables." The Corporation's share of the net income of these companies is included in the Consolidated Statement of Income caption "Income from equity affiliates."

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

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

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

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

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

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

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

Derivative Instruments. The Corporation makes limited use of derivative instruments. The Corporation does not engage in speculative derivative activities or derivative tradin activities, nor does it use derivatives with leveraged features. When the Corporation does enter into derivative transactions, it is to offset exposures associated with interest rates, foreig currency exchange rates and hydrocarbon prices that arise from existing assets, liabilities and forecasted transactions.

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

Fair Value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 and are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilitie Hierarchy

Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are no observable in the market.

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

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

The Corporation uses the “successful efforts” method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis. Cos incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. Exploratory well costs are carried as an asset when the well ha found a sufficient quantity of reserves to justify its completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic an operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual leas rentals, are expensed as incurred. Development costs including costs of productive wells and development dry holes are capitalized.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves. Capitalized exploratory drilling an development costs associated with productive depletable extractive properties are amortized using unit-of-production rates based on the amount of proved developed reserves of oil, ga and other minerals that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considere produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

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

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

The Corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations a developed using annually updated corporate plan investment evaluation assumptions for crude oil and natural gas commodity prices, refining and chemical margins and foreign currenc exchange rates. Annual volumes are based on field production profiles, which are also updated annually. Prices for other petroleum and chemical products are based on corporate pla assumptions developed annually by major region and also for investment evaluation purposes. Cash flow estimates for impairment testing exclude derivative instruments.

Impairment analyses are generally based on proved reserves. Where probable reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the impairmen evaluation. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds fa value.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance o success and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based o development risk and average holding period. 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 costs applicable to any interest retained nor any substanti obligation for future performance by the Corporation.

Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

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

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

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

Foreign Currency Translation. The Corporation selects the functional reporting currency for its international subsidiaries based on the currency of the primary economic environme in which each subsidiary operates.

Downstream and Chemical operations primarily use the local currency. However, the U.S. dollar is used in countries with a history of high inflation (primarily in Latin America) an Singapore, which predominantly sells into the U.S. dollar export market. Upstream operations which are relatively self-contained and integrated within a particular country, such a Canada, the United Kingdom, Norway and continental Europe, use the local currency. Some Upstream operations, primarily in Asia and Africa, use the U.S. dollar because the predominantly sell crude and natural gas production into U.S. dollar-denominated markets.

For all operations, gains or losses from remeasuring foreign currency transactions into the functional currency are included in income.

Stock-Based Payments. The Corporation awards stock-based compensation to employees in the form of restricted stock and restricted stock units. Compensation expense is measure by the price of the stock at the date of grant and is recognized in income over the requisite service period.

2. Accounting Changes

The Corporation did not adopt authoritative guidance in 2014 that had a material impact on the Corporation's financial statements.

In May 2014, the Financial Accounting Standards Board issued a new standard, *Revenue from Contracts with Customers*. The standard establishes a single revenue recognition mod for all contracts with customers, eliminates industry specific requirements, and expands disclosure requirements. The standard is required to be adopted beginning January 1, 201 ExxonMobil is evaluating the standard and its effect on the Corporation's financial statements.

3. Miscellaneous Financial Information

Research and development expenses totaled $971 million in 2014, $1,044 million in 2013 and $1,042 million in 2012.

Net income included before-tax aggregate foreign exchange transaction losses of $225 million, and gains of $155 million and $159 million in 2014, 2013 and 2012, respectively.

In 2014, 2013 and 2012, net income included gains of $187 million, $282 million and $328 million, respectively, attributable to the combined effects of LIFO inventory accumulatio and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $10.6 billion and $21.2 billion at December 31, 2014, and 201 respectively.

Crude oil, products and merchandise as of year-end 2014 and 2013 consist of the following:

	2014	2013
	(billions of dollars)	
Petroleum products	4.1	3.9
Crude oil	4.6	4.7
Chemical products	2.9	2.9
Gas/other	0.8	0.6
Total	12.4	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 Stock Investments**	**Total**
		(millions of dollars)		
Balance as of December 31, 2011	4,168	(13,291)	-	(9,123)
Current period change excluding amounts reclassified from accumulated other comprehensive income	842	(3,402)	-	(2,560)
Amounts reclassified from accumulated other comprehensive income	(2,600)	2,099	-	(501)
Total change in accumulated other comprehensive income	(1,758)	(1,303)	-	(3,061)
Balance as of December 31, 2012	2,410	(14,594)	-	(12,184)
Balance as of December 31, 2012	2,410	(14,594)	-	(12,184)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(3,233)	2,963	-	(270)
Amounts reclassified from accumulated other comprehensive income	(23)	1,752	-	1,729
Total change in accumulated other comprehensive income	(3,256)	4,715	-	1,459
Balance as of December 31, 2013	(846)	(9,879)	-	(10,725)
Balance as of December 31, 2013	(846)	(9,879)	-	(10,725)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(5,258)	(4,132)	(63)	(9,453)
Amounts reclassified from accumulated other comprehensive income	152	1,066	3	1,221
Total change in accumulated other comprehensive income	(5,106)	(3,066)	(60)	(8,232)
Balance as of December 31, 2014	(5,952)	(12,945)	(60)	(18,957)

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)	**2014**	**2013**	**2012**
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	(152)	23	4,35[illegible]
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs *(1)*	(1,571)	(2,616)	(3,62[illegible]
Realized change in fair value of stock investments included in net income (Statement of Income line: Other income)	(5)	-	-

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

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	**2014**	**2013**	**2012**
		(millions of dollars)	
Foreign exchange translation adjustment	292	218	(23[illegible]
Postretirement benefits reserves adjustment (excluding amortization)	2,009	(1,540)	1,61[illegible]
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(460)	(796)	(1,22[illegible]
Unrealized change in fair value of stock investments	34	-	-
Realized change in fair value of stock investments included in net income	(2)	-	-
Total	1,873	(2,118)	15[illegible]

5. Cash Flow Information

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

For 2014, the "Net (gain) on asset sales" on the Consolidated Statement of Cash Flows includes before-tax gains from the sale of Hong Kong power operations, additional proceeds related to the 2013 sale of a partial interest in Iraq, the sale of Downstream affiliates in the Caribbean and the sale or exchange of Upstream properties in the U.S., Canada, and Malaysia. For 2013, the amount includes before-tax gains from the sale of a partial interest in Iraq, the sale of Downstream affiliates in the Caribbean and the sale of service stations. For 2012, the amount includes before-tax gains related to the Japan restructuring, the sale of an Upstream property in Angola, exchanges of Upstream properties, the sale of U.S. service stations and the sale of Downstream affiliates in Malaysia and Switzerland. These gains are reported in "Other income" on the Consolidated Statement of Income.

In 2014, ExxonMobil completed asset exchanges, primarily non-cash transactions, of approximately $1.2 billion. This amount is not included in the "Sales of subsidiaries, investments and property, plant and equipment" or the "Additions to property, plant and equipment" lines on the Statement of Cash Flows.

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

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

	2014	2013	2012
		(millions of dollars)	
Cash payments for interest	380	426	555
Cash payments for income taxes	18,085	25,066	24,349

6. Additional Working Capital Information

	Dec. 31 2014	Dec. 31 2013
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $113 million and $112 million	18,541	25,993
Other, less reserves of $48 million and $28 million	9,468	7,159
Total	28,009	33,152
Notes and loans payable		
Bank loans	473	723
Commercial paper	16,225	14,051
Long-term debt due within one year	770	1,034
Total	17,468	15,808
Accounts payable and accrued liabilities		
Trade payables	25,286	30,920
Payables to equity companies	6,589	6,587
Accrued taxes other than income taxes	3,290	3,883
Other	7,062	6,695
Total	42,227	48,085

The Corporation has short-term committed lines of credit of $6.3 billion which were unused as of December 31, 2014. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 0.3 percent and 0.4 percent at December 31, 2014, and 2013, respectively.

7. Equity Company Information

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

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

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 14 percent, 13 percent and 16 percent in the years 2014, 2013 and 201 respectively.

In 2013 and 2014, the Corporation and Rosneft established various entities to conduct exploration and research activities. Periods of disproportionate funding will result in t Corporation recognizing, during the early phases of the projects, an investment that is larger than its equity share in these entities. These joint ventures are considered Variable Intere Entities. However, since the Corporation is not the primary beneficiary of these entities, the joint ventures are reported as equity companies. In 2014, the European Union and Unite States imposed sanctions relating to the Russian energy sector. In compliance with the sanctions and all general and specific licenses, prohibited activities involving offshore Russia in t Black Sea, Arctic regions, and onshore western Siberia have been wound down. The Corporation's maximum exposure to loss from these joint ventures as of December 31, 2014, is $1. billion.

Equity Company Financial Summary	2014 Total	2014 ExxonMobil Share	2013 Total	2013 ExxonMobil Share	2012 Total	2012 ExxonMobil Share
	(millions of dollars)					
Total revenues	183,708	55,855	236,161	68,084	224,953	67,57
Income before income taxes	65,549	19,014	69,454	19,999	69,411	20,88
Income taxes	20,520	5,684	21,618	6,069	20,703	5,86
Income from equity affiliates	45,029	13,330	47,836	13,930	48,708	15,01
Current assets	49,905	16,802	62,398	19,545	59,612	18,48
Long-term assets	110,754	33,619	116,450	35,695	111,131	33,79
Total assets	160,659	50,421	178,848	55,240	170,743	52,28
Current liabilities	37,333	11,472	54,550	15,243	49,698	14,26
Long-term liabilities	66,231	19,470	68,857	20,873	68,855	19,71
Net assets	57,095	19,479	55,441	19,124	52,190	18,30

A list of significant equity companies as of December 31, 2014, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	
Aera Energy LLC	48
BEB Erdgas und Erdoel GmbH & Co. KG	50
Cameroon Oil Transportation Company S.A.	41
Cross Timbers Energy, LLC	50
Golden Pass LNG Terminal LLC	18
Karmorneftegaz Holding SARL	33
Marine Well Containment Company LLC	10
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
Downstream	
Chalmette Refining, LLC	50
Fujian Refining & Petrochemical Co. Ltd.	25
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Infineum Holdings B.V.	50
Infineum USA L.P.	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2014	Dec. 31, 2013
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	20,017	19,619
Advances	9,818	10,476
Total equity company investments and advances	29,835	30,095
Companies carried at cost or less and stock investments carried at fair value	526	115
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $2,662 million and $2,938 million	4,878	6,118
Total	35,239	36,328

9. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	December 31, 2014 Cost	December 31, 2014 Net	December 31, 2013 Cost	December 31, 2013 Net
	(millions of dollars)			
Upstream	347,170	205,308	336,359	197,554
Downstream	53,327	22,639	54,456	23,219
Chemical	30,717	14,918	29,487	13,965
Other	15,575	9,803	14,215	8,912
Total	446,789	252,668	434,517	243,650

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

Accumulated depreciation and depletion totaled $194,121 million at the end of 2014 and $190,867 million at the end of 2013. Interest capitalized in 2014, 2013 and 2012 was $34 million, $309 million and $506 million, respectively.

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the asse are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligatio technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations incurred in the current period were Level fair value measurements. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserves are produced. Over time, the liabilities ar accreted for the change in their present value.

Asset retirement obligations for downstream and chemical facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations ma include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations and as such, the fair value of th conditional legal obligations cannot be measured, since it is impossible to estimate the future settlement dates of such obligations.

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

	2014	2013
	(millions of dollars)	
Beginning balance	12,988	11,973
Accretion expense and other provisions	871	785
Reduction due to property sales	(151)	(97
Payments made	(724)	(664
Liabilities incurred	122	603
Foreign currency translation	(908)	(344
Revisions	1,226	732
Ending balance	13,424	12,988

10. Accounting for Suspended Exploratory Well Costs

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

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

Change in capitalized suspended exploratory well costs:

	2014	2013	201
		(millions of dollars)	
Balance beginning at January 1	2,707	2,679	2,88
Additions pending the determination of proved reserves	1,095	293	86
Charged to expense	(28)	(52)	(9
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(160)	(107)	(63
Divestments/Other	(27)	(106)	(34
Ending balance at December 31	3,587	2,707	2,67
Ending balance attributed to equity companies included above	645	13	[illegible]

Period end capitalized suspended exploratory well costs:

	2014	2013	201
		(millions of dollars)	
Capitalized for a period of one year or less	1,095	293	86
Capitalized for a period of between one and five years	1,659	1,705	1,17
Capitalized for a period of between five and ten years	544	470	40
Capitalized for a period of greater than ten years	289	239	23
Capitalized for a period greater than one year - subtotal	2,492	2,414	1,81
Total	3,587	2,707	2,67

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

	2014	2013	201
Number of projects with first capitalized well drilled in the preceding 12 months	8	8	1
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	53	50	4
Total	61	58	5

Of the 53 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2014, 15 projects have drilling in the preceding 12 months c exploratory activity planned in the next two years, while the remaining 38 projects are those with completed exploratory activity progressing toward development. The table belo provides additional detail for those 38 projects, which total $1,035 million.

Country/Project	Dec. 31, 2014	Years Wells Drilled	Comment
	(millions of dollars)		
Angola			
- Kaombo Split Hub Phase 2	20	2005 - 2006	Evaluating development plan to tie into planned production facilities.
- Perpetua-Zinia-Acacia	15	2008 - 2009	Oil field near Pazflor development, awaiting capacity in existing/planned infrastructure.
Australia			
- East Pilchard	8	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Longtom	12	2010	Gas field near Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Remora	38	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.
- Erha Northeast	26	2008	Evaluating development plan for tieback to existing production facilities.
- Owowo	50	2009 - 2012	Continuing discussions with the government regarding contract terms.
- Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
- Satellite Field Development Phase 2	12	2013	Evaluating development plan to tie into planned production facilities.
- Other (4 projects)	14	2002	Evaluating and pursuing development of several additional discoveries.
Norway			
- Gamma	15	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- Lavrans	18	1995 - 1999	Evaluating development plan, awaiting capacity in existing Kristin production facility.
- Other (7 projects)	29	2008 - 2013	Evaluating development plans, including potential for tieback to existing production facilities.
Papua New Guinea			
- Juha	28	2007	Progressing development plans to tie into existing LNG facilities.
- P'nyang	58	2012	Evaluating development alternatives to tie into existing/planned infrastructure.
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			
- Hadrian North	209	2010 - 2013	Evaluating development plan to tie into existing production facilities.
- Tip Top	31	2009	Evaluating development concept and requisite facility upgrades.
Total 2014 (38 projects)	1,035		

11. Leased Facilities

At December 31, 2014, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering drilling equipment, tankers, service stations and other properties with minimum undiscounted lease commitments totaling $6,213 million as indicated in the table. Estimated related rental income from noncancelable subleases is $70 million.

	Lease Payments Under Minimum Commitments	**Related Sublease Rental Income**
	(millions of dollars)	
2015	2,034	31
2016	1,379	7
2017	774	6
2018	418	3
2019	312	3
2020 and beyond	1,296	20
Total	6,213	70

Net rental cost under both cancelable and noncancelable operating leases incurred during 2014, 2013 and 2012 were as follows:

	2014	**2013**	**2012**
		(millions of dollars)	
Rental cost	4,077	3,841	3,851
Less sublease rental income	52	44	44
Net rental cost	4,025	3,797	3,807

12. Earnings Per Share

	2014	**2013**	**2012**
Earnings per common share			
Net income attributable to ExxonMobil *(millions of dollars)*	32,520	32,580	44,880
Weighted average number of common shares outstanding *(millions of shares)*	4,282	4,419	4,628
Earnings per common share *(dollars) (1)*	7.60	7.37	9.70
Dividends paid per common share *(dollars)*	2.70	2.46	2.18

(1) The earnings per common share and earnings per common share - assuming dilution are the same in each period shown.

13. Financial Instruments and Derivatives

Financial Instruments. The fair value of financial instruments is determined by reference to observable market data and other valuation techniques as appropriate. The only category o financial instruments where the difference between fair value and recorded book value is notable is long-term debt. The estimated fair value of total long-term debt, excluding capitalize lease obligations, was $11.7 billion and $6.8 billion at December 31, 2014, and 2013, respectively, as compared to recorded book values of $11.3 billion and $6.5 billion at December 3 2014, and 2013, respectively. The increase in the estimated fair value and book value of long-term debt reflects the Corporation's issuance of $5,500 million of long-term debt in the firs quarter of 2014.

The fair value of long-term debt by hierarchy level at December 31, 2014, is: Level 1 $11,036 million; Level 2 $561 million; and Level 3 $63 million.

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesse reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivatives to mitigat the impact of such changes. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. Whe the Corporation does enter into derivative transactions, it is to offset exposures associated with interest rates, foreign currency exchange rates and hydrocarbon prices that arise fro 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 $75 million at year-end 2014 and a net asset of $1 million at year-en 2013. Assets and liabilities associated with derivatives are usually recorded either in "Other current assets" or "Accounts payable and accrued liabilities."

The Corporation's fair value measurement of its derivative instruments use either Level 1 or Level 2 inputs.

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of $110 million, $(7) million and $(23) million during 2014, 2013 and 2012, respectivel Income statement effects associated with derivatives are usually recorded either in "Sales and other operating revenue" or "Crude oil and product purchases."

The Corporation believes there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivative activitie described above.

14. Long-Term Debt

At December 31, 2014, long-term debt consisted of $11,341 million due in U.S. dollars and $312 million representing the U.S. dollar equivalent at year-end exchange rates of amoun payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $770 million, which matures within one year and is included in current liabilities. Tl increase in the book value of long-term debt reflects the Corporation's issuance of $5,500 million of long-term debt in the first quarter of 2014. The amounts of long-term debt maturing i each of the four years after December 31, 2015, in millions of dollars, are: 2016 – $537; 2017 – $2,993; 2018 – $872; and 2019 – $2,353. At December 31, 2014, the Corporation's unuse long-term credit lines were $0.5 billion.

Summarized long-term debt at year-end 2014 and 2013 are shown in the table below:

	2014	2013
	(millions of dollars)	
Exxon Mobil Corporation		
0.921% notes due 2017	1,500	-
Floating-rate notes due 2017 *(1)*	750	-
1.819% notes due 2019	1,750	-
Floating-rate notes due 2019 *(2)*	500	-
3.176% notes due 2024	1,000	-
XTO Energy Inc. *(3)*		
5.000% senior notes due 2015	-	132
5.300% senior notes due 2015	-	243
5.650% senior notes due 2016	207	212
6.250% senior notes due 2017	477	489
5.500% senior notes due 2018	383	389
6.500% senior notes due 2018	474	485
6.100% senior notes due 2036	199	200
6.750% senior notes due 2037	309	312
6.375% senior notes due 2038	236	238
Mobil Producing Nigeria Unlimited *(4)*		
Variable notes due 2015-2019	399	742
Esso (Thailand) Public Company Ltd. *(5)*		
Variable notes due 2015-2019	121	177
Mobil Corporation		
8.625% debentures due 2021	249	249
Industrial revenue bonds due 2015-2051 *(6)*	2,611	2,527
Other U.S. dollar obligations *(7)*	104	112
Other foreign currency obligations	9	9
Capitalized lease obligations *(8)*	375	375
Total long-term debt	11,653	6,891

(1) Average effective interest rate of 0.3% in 2014.

(2) Average effective interest rate of 0.4% in 2014.

(3) Includes premiums of $219 million in 2014 and $271 million in 2013.

(4) Average effective interest rate of 4.5% in 2014 and 4.6% in 2013.

(5) Average effective interest rate of 2.4% in 2014 and 3.3% in 2013.

(6) Average effective interest rate of 0.03% in 2014 and 0.06% in 2013.

(7) Average effective interest rate of 4.2% in 2014 and 4.4% in 2013.

(8) Average imputed interest rate of 7.0% in 2014 and 7.8% in 2013.

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of award. Awards may be granted to eligibl employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrumen Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stoc that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire or are settled in cash, do not count against this maximum limit. The 2003 Incentiv Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2014, remaining share available for award under the 2003 Incentive Program were 108 million.

Restricted Stock and Restricted Stock Units. Awards totaling 9,775 thousand, 9,729 thousand, and 10,017 thousand of restricted (nonvested) common stock and restricted (nonvestec common stock units were granted in 2014, 2013 and 2012, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized i income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their chang in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majori of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Award granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 5 percent of the award.

The Corporation has purchased shares in the open market and through negotiated transactions to offset shares issued in conjunction with benefit plans and programs. Purchases may b 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, 2014.

	2014	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	45,207	78.29
2013 award issued in 2014	9,705	94.47
Vested	(10,286)	79.89
Forfeited	(187)	78.89
Issued and outstanding at December 31	44,439	81.45

Value of restricted stock and units	**2014**	**2013**	**201**
Grant price *(dollars)*	95.20	94.47	87.2
Value at date of grant:		*(millions of dollars)*	
Restricted stock and units settled in stock	858	843	79
Units settled in cash	73	76	7
Total value	931	919	87

As of December 31, 2014, there was $2,339 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighte average period of 4.5 years. The compensation cost charged against income for the restricted stock and restricted stock units was $831 million, $854 million and $854 million for 201 2013 and 2012, respectively. The income tax benefit recognized in income related to this compensation expense was $76 million, $78 million and $79 million for the same period respectively. The fair value of shares and units vested in 2014, 2013 and 2012 was $946 million, $1,040 million and $926 million, respectively. Cash payments of $73 million, $67 millio and $66 million for vested restricted stock units settled in cash were made in 2014, 2013 and 2012, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

16. Litigation and Other Contingencies

Litigation. A variety of claims have been made against ExxonMobil and certain of its consolidated subsidiaries in a number of pending lawsuits. Management has regular litigatio reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The Corporation accrues an undiscounte liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amou within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Corporation does not record liabilities when the likelihood that the liability h been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where a unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. F purposes of our contingency disclosures, "significant" includes material matters as well as other matters which management believes should be disclosed. ExxonMobil will continue t defend itself vigorously in these matters. Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pendir lawsuit against ExxonMobil will have a material adverse effect upon the Corporation's operations, financial condition, or financial statements taken as a whole.

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2014, for guarantees relating to notes, loans and performanc under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximur potential exposure.

	Dec. 31, 2014		
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	3,506	41	3,54
Other	2,920	3,982	6,90
Total	6,426	4,023	10,44

(1) ExxonMobil share.

The debt-related guarantees shown above include a $3.4 billion completion guarantee provided to lenders in support of the project financing for the Papua New Guinea Liquefied Natur Gas project. On February 4, 2015, the obligations under this guarantee were terminated per the terms of the loan agreement.

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

	Payments Due by Period			
	2015	**2016-2019**	**2020 and Beyond**	**Total**
		(millions of dollars)		
Unconditional purchase obligations *(1)*	150	608	337	1,09

(1) Undiscounted obligations of $1,095 million mainly pertain to pipeline throughput agreements and include $433 million of obligations to equity companies. The present value of th commitments, which excludes imputed interest of $168 million, totaled $927 million.

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

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID) invoking ICSI jurisdiction under Venezuela’s Investment Law and the Netherlands-Venezuela Bilateral Investment Treaty. The ICSID Tribunal issued a decision on June 10, 2010, finding that it ha jurisdiction to proceed on the basis of the Netherlands-Venezuela Bilateral Investment Treaty. On October 9, 2014, the ICSID Tribunal issued its final award finding in favor of th ExxonMobil affiliates and awarding $1.6 billion as of the date of expropriation, June 27, 2007, and interest from that date at 3.25% compounded annually until the date of payment in ful The Tribunal also noted that one of the Cerro Negro Project agreements provides a mechanism to prevent double recovery between the ICSID award and all or part of an earlier award o $908 million to an ExxonMobil affiliate, Mobil Cerro Negro, Ltd., against PdVSA and a PdVSA affiliate, PdVSA CN, in an arbitration under the rules of the International Chamber o Commerce (ICC). Following the favorable ICSID decision in the fourth quarter of 2014, ExxonMobil recognized earnings of $269 million, net of the remaining asset value, for th proceeds received from the earlier ICC award.

Judgment was entered on the ICSID award by the United States District Court for the Southern District of New York on October 10, 2014. A motion to vacate that judgment o procedural grounds was filed by the Republic of Venezuela on October 14, 2014, which was denied by the court. Thereafter, the Republic of Venezuela filed a motion to modify th judgment by reducing the rate of interest to be paid on the ICSID award from the entry of the court’s judgment, until the date of payment.

On October 23, 2014, the Republic of Venezuela filed with ICSID an application to revise the ICSID award such that it requires repayment of the value of the ICC award to PdVSA a the same time as payment is made to the ExxonMobil affiliates for the ICSID award and that provision be made for interest on the amount to be repaid. Thereafter, pursuant to ICSI arbitration rules, the ICSID award was stayed pending further action of the Tribunal. On October 27, 2014, ExxonMobil filed a response with ICSID that contests the application fo revision of that award on both factual and jurisdictional grounds. On February 2, 2015, the Republic of Venezuela filed an application to annul the ICSID award. The application allege that, in issuing the ICSID award, the Tribunal exceeded its powers, failed to state reasons on which the ICSID award was based, and departed from a fundamental rule of procedure. Upo registration of the application with ICSID on February 9, 2015, a further stay of the ICSID award was entered.

The federal court in New York has stayed its judgment until such time as the stays of the ICSID award entered following the Government of Venezuela’s filing of its two application have been lifted. The net impact of these matters on the Corporation’s consolidated financial results cannot be reasonably estimated. Regardless, the Corporation does not expect th resolution to have a material effect upon the Corporation’s operations or financial condition.

An affiliate of ExxonMobil is one of the Contractors under a Production Sharing Contract (PSC) with the Nigerian National Petroleum Corporation (NNPC) covering the Erha bloc located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the block and owns a 56.25 percent interest under the PSC. The Contractors are in dispute with NNP regarding NNPC's lifting of crude oil in excess of its entitlement under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuj Nigeria, under the Nigerian Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholding the Contractors' position in all materia respects and awarding damages to the Contractors jointly in an amount of approximately $1.8 billion plus $234 million in accrued interest. The Contractors petitioned a Nigerian feder court for enforcement of the award, and NNPC petitioned the same court to have the award set aside. On May 22, 2012, the court set aside the award. The Contractors have appealed th judgment. In June 2013, the Contractors filed a lawsuit against NNPC in the Nigerian federal high court in order to preserve their ability to seek enforcement of the PSC in the courts necessary. In October 2014, the Contractors filed suit in the United States District Court for the Southern District of New York to enforce, if necessary, the arbitration award against NNP assets residing within that jurisdiction. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, regardless o the outcome of enforcement proceedings, the Corporation does not expect the proceedings to have a material effect upon the Corporation's operations or financial condition.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2014	2013	2014	2013	2014	2013
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	4.00	5.00	3.10	4.30	4.00	5.0
Long-term rate of compensation increase	5.75	5.75	5.30	5.40	5.75	5.7
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	17,304	19,779	27,357	28,670	7,868	9,05
Service cost	677	801	590	697	140	17
Interest cost	807	749	1,138	1,076	383	35
Actuarial loss/(gain)	3,192	(1,520)	4,929	(1,454)	1,522	(1,26
Benefits paid *(1) (2)*	(1,427)	(2,520)	(1,366)	(1,311)	(525)	(51
Foreign exchange rate changes	-	-	(2,540)	(284)	(48)	(4
Amendments, divestments and other	(24)	15	(61)	(37)	96	10
Benefit obligation at December 31	20,529	17,304	30,047	27,357	9,436	7,86
Accumulated benefit obligation at December 31	16,385	13,989	26,318	23,949	-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2014 and 2013, other postretirement benefits paid are net of $21 million and $20 million of Medicare subsidy receipts, respectively.

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the discount rate determined by use of a yiel curve based on high-quality, noncallable bonds with cash flows that match estimated outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by usin bond portfolios with an average maturity approximating that of the liabilities or spot yield curves, both of which are constructed using high-quality, local-currency-denominated bonds.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.5 percent in 2016 and subsequent years. A one-percentage-poir increase in the health care cost trend rate would increase service and interest cost by $91 million and the postretirement benefit obligation by $1,070 million. A one-percentage-poir decrease in the health care cost trend rate would decrease service and interest cost by $69 million and the postretirement benefit obligation by $844 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2014	2013	2014	2013	2014	2013
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	11,190	12,632	19,283	18,090	620	58
Actual return on plan assets	1,497	617	3,153	1,604	41	6
Foreign exchange rate changes	-	-	(1,738)	(270)	-	-
Company contribution	1,476	101	554	919	31	3
Benefits paid *(1)*	(1,248)	(2,171)	(912)	(869)	(224)	(6
Other	-	11	(245)	(191)	-	-
Fair value at December 31	12,915	11,190	20,095	19,283	468	62

(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 table below, certain smaller U.S. pension plans an a number of non-U.S. pension plans are not funded because local tax conventions and regulatory practices do not encourage funding of these plans. All defined benefit pension obligation regardless of the funding status of the underlying plans, are fully supported by the financial strength of the Corporation or the respective sponsoring affiliate.

	Pension Benefits			
	U.S.		Non-U.S.	
	2014	2013	2014	2013
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(4,590)	(3,547)	(2,113)	(94
Unfunded plans	(3,024)	(2,567)	(7,839)	(7,13
Total	(7,614)	(6,114)	(9,952)	(8,07

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2014	2013	2014	2013	2014	2013
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(7,614)	(6,114)	(9,952)	(8,074)	(8,968)	(7,24
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	-	1	302	201	-	-
Current liabilities	(340)	(275)	(325)	(358)	(369)	(35
Postretirement benefits reserves	(7,274)	(5,840)	(9,929)	(7,917)	(8,599)	(6,88
Total recorded	(7,614)	(6,114)	(9,952)	(8,074)	(8,968)	(7,24
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	6,589	4,780	9,642	7,943	2,997	1,60
Prior service cost	27	60	429	665	51	6
Total recorded in accumulated other comprehensive income	6,616	4,840	10,071	8,608	3,048	1,66

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

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

	Pension Benefits						**Other Postretirement Benefits**		
	U.S.			**Non-U.S.**					
	2014	**2013**	**2012**	**2014**	**2013**	**2012**	**2014**	**2013**	**2012**
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					*(percent)*				
Discount rate	5.00	4.00	5.00	4.30	3.80	4.00	5.00	4.00	5.0
Long-term rate of return on funded assets	7.25	7.25	7.25	6.30	6.40	6.60	7.25	7.25	7.2
Long-term rate of compensation increase	5.75	5.75	5.75	5.40	5.50	5.40	5.75	5.75	5.7
Components of net periodic benefit cost					*(millions of dollars)*				
Service cost	677	801	665	590	697	648	140	176	13
Interest cost	807	749	820	1,138	1,076	1,145	383	352	38
Expected return on plan assets	(799)	(835)	(789)	(1,193)	(1,128)	(1,109)	(37)	(41)	(3
Amortization of actuarial loss/(gain)	409	646	576	628	852	844	116	228	17
Amortization of prior service cost	8	7	7	120	117	117	14	21	3
Net pension enhancement and curtailment/settlement cost *(1)*	276	723	333	-	22	1,540	-	-	-
Net periodic benefit cost	1,378	2,091	1,612	1,283	1,636	3,185	616	736	68

(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".*

Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	2,494	(1,302)	1,885	2,969	(1,938)	1,906	1,518	(1,290)	1,00
Amortization of actuarial (loss)/gain	(685)	(1,369)	(909)	(628)	(874)	(2,384)	(116)	(228)	(17
Prior service cost/(credit)	(25)	-	-	(70)	30	71	-	-	-
Amortization of prior service (cost)/credit	(8)	(7)	(7)	(120)	(117)	(117)	(14)	(21)	(3
Foreign exchange rate changes	-	-	-	(688)	(155)	271	(8)	(10)	[illegible]
Total recorded in other comprehensive income	1,776	(2,678)	969	1,463	(3,054)	(253)	1,380	(1,549)	80
Total recorded in net periodic benefit cost and other comprehensive income, before tax	3,154	(587)	2,581	2,746	(1,418)	2,932	1,996	(813)	1,48

Costs for defined contribution plans were $393 million, $392 million and $382 million in 2014, 2013 and 2012, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2014	2013	2012
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	(1,776)	2,678	(96
Non-U.S. pension	(1,463)	3,054	25
Other postretirement benefits	(1,380)	1,549	(80
Total (charge)/credit to other comprehensive income, before tax	(4,619)	7,281	(1,52
(Charge)/credit to income tax (see Note 4)	1,549	(2,336)	39
(Charge)/credit to investment in equity companies	(81)	49	(4
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	(3,151)	4,994	(1,17
Charge/(credit) to equity of noncontrolling interests	85	(279)	(12
(Charge)/credit to other comprehensive income attributable to ExxonMobil	(3,066)	4,715	(1,30

The Corporation's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification t reduce the risk of the portfolio. The benefit plan assets are primarily invested in passive equity and fixed income index funds to diversify risk while minimizing costs. The equity func hold ExxonMobil stock only to the extent necessary to replicate the relevant equity index. The fixed income funds are largely invested in high-quality corporate and government de securities.

Studies are periodically conducted to establish the preferred target asset allocation percentages. The target asset allocation for the U.S. benefit plans and for the non-U.S. plans aggregate is 40 percent equity securities and 60 percent debt securities. The equity targets for the U.S. and non-U.S. plans include an allocation to private equity partnerships that primari focus on early-stage venture capital of 5 percent and 3 percent, respectively.

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

The 2014 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, 2014, Using:				Non-U.S. Pension Fair Value Measurement at December 31, 2014, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
				(millions of dollars)				
Asset category:								
Equity securities								
U.S.	-	2,331 *(1)*	-	2,331	-	3,284 *(1)*	-	3,28
Non-U.S.	-	2,144 *(1)*	-	2,144	229 *(2)*	3,776 *(1)*	-	4,00
Private equity	-	-	562 *(3)*	562	-	-	535 *(3)*	53
Debt securities								
Corporate	-	4,841 *(4)*	-	4,841	-	2,686 *(4)*	-	2,68
Government	-	2,890 *(4)*	-	2,890	249 *(5)*	9,050 *(4)*	-	9,29
Asset-backed	-	5 *(4)*	-	5	-	146 *(4)*	-	14
Real estate funds	-	-	-	-	-	-	57 *(6)*	5
Cash	-	131 *(7)*	-	131	25	31 *(8)*	-	5
Total at fair value	-	12,342	562	12,904	503	18,973	592	20,06
Insurance contracts								
at contract value				11				2
Total plan assets				12,915				20,09

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

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

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

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

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

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

(7) For cash balances held in the form of short-term fund units that are redeemable at the measurement date, the fair value is treated as a Level 2 input.

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

	Other Postretirement			
	Fair Value Measurement at December 31, 2014, Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(millions of dollars)		
Asset category:				
Equity securities				
U.S.	-	106 (1)	-	106
Non-U.S.	-	75 (1)	-	75
Private equity	-	-	2 (2)	2
Debt securities				
Corporate	-	103 (3)	-	103
Government	-	171 (3)	-	171
Asset-backed	-	9 (3)	-	9
Cash	-	2	-	2
Total at fair value	-	466	2	468

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

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

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

The change in the fair value in 2014 of Level 3 assets that use significant unobservable inputs to measure fair value is shown in the table below:

	2014			
	Pension			Other
	U.S.	Non-U.S.		Postretirement
	Private Equity	Private Equity	Real Estate	Private Equity
		(millions of dollars)		
Fair value at January 1	523	502	136	9
Net realized gains/(losses)	2	23	(17)	-
Net unrealized gains/(losses)	89	31	8	-
Net purchases/(sales)	(52)	(21)	(70)	(7)
Fair value at December 31	562	535	57	2

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 Fair Value Measurement at December 31, 2013, Using:				Non-U.S. Pension 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)	Total
				(millions of dollars)				
Asset category:								
Equity securities								
U.S.	-	2,514 *(1)*	-	2,514	-	3,046 *(1)*	-	3,04
Non-U.S.	-	2,622 *(1)*	-	2,622	294 *(2)*	5,608 *(1)*	-	5,90
Private equity	-	-	523 *(3)*	523	-	-	502 *(3)*	50
Debt securities								
Corporate	-	3,430 *(4)*	-	3,430	-	2,125 *(4)*	-	2,12
Government	-	2,056 *(4)*	-	2,056	272 *(5)*	7,100 *(4)*	-	7,37
Asset-backed	-	6 *(4)*	-	6	-	103 *(4)*	-	10
Real estate funds	-	-	-	-	-	-	136 *(6)*	13
Cash	-	27 *(7)*	-	27	57	20 *(8)*	-	7
Total at fair value	-	10,655	523	11,178	623	18,002	638	19,26
Insurance contracts at contract value				12				2
Total plan assets				11,190				19,28

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

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

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

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

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

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

(7) For cash balances held in the form of short-term fund units that are redeemable at the measurement date, the fair value is treated as a Level 2 input.

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

	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)	Total
	(millions of dollars)			
Asset category:				
Equity securities				
U.S.	-	157 *(1)*	-	15
Non-U.S.	-	149 *(1)*	-	14
Private equity	-	-	9 *(2)*	
Debt securities				
Corporate	-	129 *(3)*	-	12
Government	-	168 *(3)*	-	16
Asset-backed	-	4 *(3)*	-	
Cash	-	4	-	
Total at fair value	-	611	9	62

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

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

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

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

	2013			
	Pension			Other Postretirement
	U.S.	Non-U.S.		
	Private Equity	Private Equity	Real Estate	Private Equity
	(millions of dollars)			
Fair value at January 1	489	448	293	7
Net realized gains/(losses)	(1)	11	(13)	-
Net unrealized gains/(losses)	86	57	10	3
Net purchases/(sales)	(51)	(14)	(154)	(1)
Fair value at December 31	523	502	136	9

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.	
	2014	2013	2014	2013
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	17,505	14,737	5,031	891
Accumulated benefit obligation	14,493	12,342	4,590	689
Fair value of plan assets	12,915	11,189	3,890	611
For unfunded pension plans:				
Projected benefit obligation	3,024	2,567	7,839	7,13
Accumulated benefit obligation	1,892	1,647	6,573	6,07

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2015 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	1,001	753	211
Prior service cost *(2)*	6	105	14

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

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

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2015	-	560	-	-
Benefit payments expected in:				
2015	1,628	1,194	467	24
2016	1,554	1,213	479	25
2017	1,529	1,278	490	26
2018	1,445	1,298	499	28
2019	1,410	1,339	507	29
2020 - 2024	6,714	6,988	2,613	172

18. Disclosures about Segments and Related Information

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

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

Earnings after income tax include transfers at estimated market prices.

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In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense $129 million and $202 million in 2014 and 2012, respectively. For 2013, non-debt-related interest expense was a net credit of $123 million, primarily reflecting the effect of credits fro the favorable resolution of prior year tax positions.

	Upstream		Downstream		Chemical		Corporate and Financing	Corporate Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.		
				(millions of dollars)				
As of December 31, 2014								
Earnings after income tax	5,197	22,351	1,618	1,427	2,804	1,511	(2,388)	32,52
Earnings of equity companies included above	1,235	10,859	29	82	186	1,377	(445)	13,32
Sales and other operating revenue *(1)*	14,826	22,336	118,771	199,976	15,115	23,063	18	394,10
Intersegment revenue	7,723	38,846	17,281	44,231	10,117	8,098	274	-
Depreciation and depletion expense	5,139	8,523	654	1,228	370	645	738	17,29
Interest revenue	-	-	-	-	-	-	75	7
Interest expense	40	17	6	4	-	-	219	28
Income taxes	1,300	15,165	610	968	1,032	358	(1,418)	18,01
Additions to property, plant and equipment	9,098	19,225	1,050	1,356	1,564	564	1,399	34,25
Investments in equity companies	5,089	10,877	69	1,006	258	3,026	(308)	20,01
Total assets	92,555	161,033	18,371	33,299	8,798	18,449	16,988	349,49
As of December 31, 2013								
Earnings after income tax	4,191	22,650	2,199	1,250	2,755	1,073	(1,538)	32,58
Earnings of equity companies included above	1,576	11,627	(460)	22	189	1,422	(449)	13,92
Sales and other operating revenue *(1)*	13,712	25,349	123,802	218,904	15,295	23,753	21	420,83
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	17,18
Interest revenue	-	-	-	-	-	-	87	8
Interest expense	30	26	7	8	1	-	(63)	[illegible]
Income taxes	2,197	21,554	721	481	989	363	(2,042)	24,26
Additions to property, plant and equipment	7,480	26,075	616	1,072	840	272	1,386	37,74
Investments in equity companies	4,975	9,740	62	1,749	217	3,103	(227)	19,61
Total assets	88,698	157,465	19,261	40,661	7,816	19,659	13,248	346,80
As of December 31, 2012								
Earnings after income tax	3,925	25,970	3,575	9,615	2,220	1,678	(2,103)	44,88
Earnings of equity companies included above	1,759	11,900	6	387	183	1,267	(492)	15,01
Sales and other operating revenue *(1)*	11,039	27,673	125,088	248,959	14,723	24,003	24	451,50
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	15,88
Interest revenue	-	-	-	-	-	-	117	11
Interest expense	37	13	3	36	-	(1)	239	32
Income taxes	2,025	25,362	1,811	1,892	755	232	(1,032)	31,04
Additions to property, plant and equipment	9,697	21,769	480	1,153	338	659	1,083	35,17
Investments in equity companies	4,020	9,147	195	2,069	233	3,143	(277)	18,53
Total assets	86,146	140,848	18,451	40,956	7,238	18,886	21,270	333,79

(1) Sales and other operating revenue includes sales-based taxes of $29,342 million for 2014, $30,589 million for 2013 and $32,409 million for 2012. See Note 1, Summar Accounting Policies.

Geographic

Sales and other operating revenue *(1)*	**2014**	**2013**	**2012**
		(millions of dollars)	
United States	148,713	152,820	150,86
Non-U.S.	245,392	268,016	300,64
Total	394,105	420,836	451,50
Significant non-U.S. revenue sources include:			
Canada	36,072	35,924	34,32
United Kingdom	31,346	34,061	33,60
Belgium	20,953	20,973	23,56
Italy	18,880	19,273	18,22
France	17,639	18,444	19,60
Singapore	15,407	15,623	14,60
Germany	14,816	15,701	15,87

(1) Sales and other operating revenue includes sales-based taxes of $29,342 million for 2014, $30,589 million for 2013 and $32,409 million for 2012. See Note 1, Summary of Accoun Policies.

Long-lived assets	**2014**	**2013**	**2012**
		(millions of dollars)	
United States	104,000	98,271	94,33
Non-U.S.	148,668	145,379	132,61
Total	252,668	243,650	226,94
Significant non-U.S. long-lived assets include:			
Canada	43,858	41,522	31,97
Australia	15,328	14,258	13,41
Nigeria	12,265	12,343	12,21
Singapore	9,620	9,570	9,70
Kazakhstan	9,138	8,530	7,78
Angola	9,057	8,262	8,23
Papua New Guinea	6,099	5,768	4,59
Norway	5,139	6,542	7,04

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

19. Income, Sales-Based and Other Taxes

	2014			2013			2012		
	U.S.	**Non-U.S.**	**Total**	**U.S.**	**Non-U.S.**	**Total**	**U.S.**	**Non-U.S.**	**Total**
					(millions of dollars)				
Income tax expense									
Federal and non-U.S.									
Current	1,456	14,755	16,211	1,073	22,115	23,188	1,791	25,650	27,441
Deferred - net	900	1,398	2,298	(116)	757	641	1,097	1,816	2,913
U.S. tax on non-U.S. operations	5	-	5	37	-	37	89	-	89
Total federal and non-U.S.	2,361	16,153	18,514	994	22,872	23,866	2,977	27,466	30,443
State *(1)*	(499)	-	(499)	397	-	397	602	-	602
Total income tax expense	1,862	16,153	18,015	1,391	22,872	24,263	3,579	27,466	31,045
Sales-based taxes	6,310	23,032	29,342	5,992	24,597	30,589	5,785	26,624	32,409
All other taxes and duties									
Other taxes and duties	378	31,908	32,286	955	32,275	33,230	1,406	34,152	35,558
Included in production and manufacturing expenses	1,454	1,179	2,633	1,318	1,182	2,500	1,242	1,308	2,550
Included in SG&A expenses	155	441	596	150	516	666	154	595	749
Total other taxes and duties	1,987	33,528	35,515	2,423	33,973	36,396	2,802	36,055	38,857
Total	10,159	72,713	82,872	9,806	81,442	91,248	12,166	90,145	102,311

(1) In 2014, state taxes included a favorable adjustment of deferred taxes of approximately $830 million.

All other taxes and duties include taxes reported in production and manufacturing and selling, general and administrative (SG&A) expenses. The above provisions for deferred incom taxes include net credits of $40 million in 2014 and $310 million in 2013 and a net charge of $244 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 2014, 2013 and 2012 is as follows:

	2014	**2013**	**2012**
		(millions of dollars)	
Income before income taxes			
United States	9,080	9,746	11,222
Non-U.S.	42,550	47,965	67,504
Total	51,630	57,711	78,726
Theoretical tax	18,071	20,199	27,554
Effect of equity method of accounting	(4,663)	(4,874)	(5,254)
Non-U.S. taxes in excess of theoretical U.S. tax	5,442	10,528	8,434
U.S. tax on non-U.S. operations	5	37	89
State taxes, net of federal tax benefit	(324)	258	391
Other	(516)	(1,885)	(169)
Total income tax expense	18,015	24,263	31,045
Effective tax rate calculation			
Income taxes	18,015	24,263	31,045
ExxonMobil share of equity company income taxes	5,678	6,061	5,859
Total income taxes	23,693	30,324	36,904
Net income including noncontrolling interests	33,615	33,448	47,681
Total income before taxes	57,308	63,772	84,585
Effective income tax rate	41%	48%	44%

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

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

Tax effects of temporary differences for:	**2014**	**2013**
	(millions of dollars)	
Property, plant and equipment	51,643	50,884
Other liabilities	4,359	3,474
Total deferred tax liabilities	56,002	54,358
Pension and other postretirement benefits	(8,140)	(6,573
Asset retirement obligations	(6,162)	(6,083
Tax loss carryforwards	(4,099)	(3,393
Other assets	(6,446)	(6,246
Total deferred tax assets	(24,847)	(22,295
Asset valuation allowances	2,570	2,49
Net deferred tax liabilities	33,725	34,554

In 2014, asset valuation allowances of $2,570 million increased by $79 million and included additional net provisions of $340 million and effects of foreign currency translation of $(26
million.

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

Balance sheet classification	**2014**	**2013**
	(millions of dollars)	
Other current assets	(2,001)	(3,575
Other assets, including intangibles, net	(3,955)	(2,822
Accounts payable and accrued liabilities	451	421
Deferred income tax liabilities	39,230	40,530
Net deferred tax liabilities	33,725	34,554

The Corporation had $51 billion of indefinitely reinvested, undistributed earnings from subsidiary companies outside the U.S. Unrecognized deferred taxes on remittance of these fun
are not expected to be material.

Unrecognized Tax Benefits. The Corporation is subject to income taxation in many jurisdictions around the world. Unrecognized tax benefits reflect the difference between positio taken or expected to be taken on income tax returns and the amounts recognized in the financial statements. The following table summarizes the movement in unrecognized tax benefits:

Gross unrecognized tax benefits	2014	2013	2012
		(millions of dollars)	
Balance at January 1	7,838	7,663	4,92
Additions based on current year's tax positions	1,454	1,460	1,66
Additions for prior years' tax positions	448	464	2,55
Reductions for prior years' tax positions	(532)	(249)	(53
Reductions due to lapse of the statute of limitations	(117)	(588)	(7
Settlements with tax authorities	(43)	(849)	(85
Foreign exchange effects/other	(62)	(63)	(1
Balance at December 31	8,986	7,838	7,66

The gross unrecognized tax benefit balances shown above are predominantly related to tax positions that would reduce the Corporation's effective tax rate if the positions are favorabl resolved. Unfavorable resolution of these tax positions generally would not increase the effective tax rate. The 2014, 2013 and 2012 changes in unrecognized tax benefits did not have material effect on the Corporation's net income.

Resolution of these tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. It is difficult to predict the timing resolution for tax positions since such timing is not entirely within the control of the Corporation. It is reasonably possible that the total amount of unrecognized tax benefits could increa by up to 30 percent in the next 12 months, with no material impact on the Corporation's net income.

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

Country of Operation	Open Tax Years
Abu Dhabi	2012 - 2014
Angola	2009 - 2014
Australia:	2000 - 2003
	2005
	2008 - 2014
Canada	2007 - 2014
Equatorial Guinea	2007 - 2014
Malaysia	2008 - 2014
Nigeria	2004 - 2014
Norway	2005 - 2014
Qatar	2008 - 2014
Russia	2011 - 2014
United Kingdom	2010 - 2014
United States	2006 - 2014

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

The Corporation incurred $42 million in interest expense on income tax reserves in 2014. For 2013, the Corporation's net interest expense was a credit of $207 million, reflecting th effect of credits from the favorable resolution of prior year tax positions. The Corporation incurred $46 million in interest expense in 2012. The related interest payable balances were $2 million and $156 million at December 31, 2014, and 2013, 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 in the Upstream function, such as oil and ga transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments fo noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $3,223 million in 2014, $886 million in 2013, and $2,832 million in 2012. Oil sand mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations	**United States**	**Canada/ South America**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)			
Consolidated Subsidiaries							
2014 - Revenue							
Sales to third parties	9,453	2,841	4,608	1,943	4,383	1,374	24,602
Transfers	5,554	5,417	5,206	14,884	7,534	1,553	40,148
	15,007	8,258	9,814	16,827	11,917	2,927	64,750
Production costs excluding taxes	4,637	4,251	3,117	2,248	1,568	583	16,404
Exploration expenses	231	363	274	427	287	87	1,669
Depreciation and depletion	4,877	1,193	1,929	3,387	1,242	454	13,082
Taxes other than income	1,116	160	412	1,539	1,542	399	5,168
Related income tax	1,208	524	2,954	5,515	4,882	435	15,518
Results of producing activities for consolidated subsidiaries	2,938	1,767	1,128	3,711	2,396	969	12,909
Equity Companies							
2014 - Revenue							
Sales to third parties	1,239	-	4,923	-	20,028	-	26,190
Transfers	924	-	63	-	685	-	1,672
	2,163	-	4,986	-	20,713	-	27,862
Production costs excluding taxes	620	-	602	-	548	-	1,770
Exploration expenses	61	-	22	-	219	-	302
Depreciation and depletion	253	-	195	-	383	-	831
Taxes other than income	57	-	2,650	-	5,184	-	7,891
Related income tax	-	-	553	-	5,099	-	5,652
Results of producing activities for equity companies	1,172	-	964	-	9,280	-	11,416
Total results of operations	4,110	1,767	2,092	3,711	11,676	969	24,325

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2013 - Revenue							
Sales to third parties	8,371	2,252	5,649	3,079	5,427	730	25,508
Transfers	6,505	5,666	5,654	15,738	8,936	1,405	43,904
	14,876	7,918	11,303	18,817	14,363	2,135	69,412
Production costs excluding taxes	4,191	3,965	2,859	2,396	1,763	654	15,828
Exploration expenses	394	386	245	288	571	92	1,976
Depreciation and depletion	4,926	989	1,881	3,269	1,680	334	13,079
Taxes other than income	1,566	94	474	1,583	1,794	427	5,938
Related income tax	1,788	542	4,124	6,841	5,709	202	19,206
Results of producing activities for consolidated subsidiaries	2,011	1,942	1,720	4,440	2,846	426	13,385
Equity Companies							
2013 - Revenue							
Sales to third parties	1,320	-	6,768	-	21,463	-	29,551
Transfers	1,034	-	64	-	6,091	-	7,189
	2,354	-	6,832	-	27,554	-	36,740
Production costs excluding taxes	551	-	459	-	660	-	1,670
Exploration expenses	19	-	15	-	426	-	460
Depreciation and depletion	207	-	169	-	955	-	1,331
Taxes other than income	51	-	3,992	-	7,352	-	11,395
Related income tax	-	-	832	-	8,482	-	9,314
Results of producing activities for equity companies	1,526	-	1,365	-	9,679	-	12,570
Total results of operations	3,537	1,942	3,085	4,440	12,525	426	25,955
Consolidated Subsidiaries							
2012 - Revenue							
Sales to third parties	6,977	1,804	5,835	3,672	6,536	1,275	26,099
Transfers	6,996	5,457	6,366	16,905	9,241	932	45,897
	13,973	7,261	12,201	20,577	15,777	2,207	71,996
Production costs excluding taxes	4,044	3,079	2,443	2,395	1,606	488	14,055
Exploration expenses	391	292	274	234	513	136	1,840
Depreciation and depletion	4,862	848	1,559	2,879	1,785	264	12,197
Taxes other than income	1,963	89	513	1,702	2,248	446	6,961
Related income tax	1,561	720	5,413	8,091	6,616	281	22,682
Results of producing activities for consolidated subsidiaries	1,152	2,233	1,999	5,276	3,009	592	14,261
Equity Companies							
2012 - Revenue							
Sales to third parties	1,284	-	6,380	-	20,017	-	27,681
Transfers	1,108	-	67	-	5,693	-	6,868
	2,392	-	6,447	-	25,710	-	34,549
Production costs excluding taxes	467	-	369	-	484	-	1,320
Exploration expenses	9	-	17	-	-	-	26
Depreciation and depletion	176	-	152	-	676	-	1,004
Taxes other than income	42	-	3,569	-	6,658	-	10,269
Related income tax	-	-	894	-	8,234	-	9,128
Results of producing activities for equity companies	1,698	-	1,446	-	9,658	-	12,802
Total results of operations	2,850	2,233	3,445	5,276	12,667	592	27,063

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $12,856 million less at year-end 2014 and $13,667 million less at year-end 2013 than the amounts reported a investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relatin to LNG operations. Assets related to oil sands 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**	**Total**
					(millions of dollars)			
Consolidated Subsidiaries								
As of December 31, 2014								
Property (acreage) costs	- Proved	14,664	2,598	161	876	1,660	808	20,767
	- Unproved	24,062	4,824	74	615	601	136	30,312
Total property costs		38,726	7,422	235	1,491	2,261	944	51,079
Producing assets		79,138	32,635	39,996	44,700	30,219	10,051	236,739
Incomplete construction		7,051	15,344	2,114	6,075	10,163	4,621	45,368
Total capitalized costs		124,915	55,401	42,345	52,266	42,643	15,616	333,186
Accumulated depreciation and depletion		43,031	15,197	32,608	27,995	17,273	4,630	140,734
Net capitalized costs for consolidated subsidiaries		81,884	40,204	9,737	24,271	25,370	10,986	192,452
Equity Companies								
As of December 31, 2014								
Property (acreage) costs	- Proved	78	-	4	-	-	-	82
	- Unproved	35	-	-	-	59	-	94
Total property costs		113	-	4	-	59	-	176
Producing assets		5,538	-	5,309	-	8,500	-	19,347
Incomplete construction		473	-	251	-	2,972	-	3,696
Total capitalized costs		6,124	-	5,564	-	11,531	-	23,219
Accumulated depreciation and depletion		1,872	-	4,205	-	5,095	-	11,172
Net capitalized costs for equity companies		4,252	-	1,359	-	6,436	-	12,047
Consolidated Subsidiaries								
As of December 31, 2013								
Property (acreage) costs	- Proved	13,881	3,595	188	874	1,620	863	21,021
	- Unproved	23,945	5,390	61	583	701	146	30,826
Total property costs		37,826	8,985	249	1,457	2,321	1,009	51,847
Producing assets		74,743	34,487	44,161	40,424	30,082	7,973	231,870
Incomplete construction		5,640	11,811	2,219	5,913	8,387	4,194	38,164
Total capitalized costs		118,209	55,283	46,629	47,794	40,790	13,176	321,881
Accumulated depreciation and depletion		39,505	16,827	35,108	24,570	17,455	4,529	137,994
Net capitalized costs for consolidated subsidiaries		78,704	38,456	11,521	23,224	23,335	8,647	183,887
Equity Companies								
As of December 31, 2013								
Property (acreage) costs	- Proved	77	-	5	-	-	-	82
	- Unproved	40	-	-	-	17	-	57
Total property costs		117	-	5	-	17	-	139
Producing assets		5,206	-	6,039	-	8,397	-	19,642
Incomplete construction		416	-	201	-	1,452	-	2,069
Total capitalized costs		5,739	-	6,245	-	9,866	-	21,850
Accumulated depreciation and depletion		1,646	-	4,778	-	4,706	-	11,130
Net capitalized costs for equity companies		4,093	-	1,467	-	5,160	-	10,720

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations establishe in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred i 2014 were $29,115 million, down $4,508 million from 2013, due primarily to lower property acquisition costs and development costs. In 2013 costs were $33,623 million, up $2,47 million from 2012, due primarily to higher property acquisition costs partially offset by lower exploration costs. Total equity company costs incurred in 2014 were $2,677 million, up $33 million from 2013, due primarily to exploration costs.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		**United States**	**Canada/ South America**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
					(millions of dollars)			
During 2014								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	80	-	-	-	41	-	121
	- Unproved	1,253	3	19	34	-	-	1,309
Exploration costs		319	453	458	628	467	121	2,446
Development costs		7,540	6,877	1,390	4,255	3,321	1,856	25,239
Total costs incurred for consolidated subsidiaries		9,192	7,333	1,867	4,917	3,829	1,977	29,115
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	42	-	42
Exploration costs		17	-	45	-	964	-	1,026
Development costs		490	-	233	-	886	-	1,609
Total costs incurred for equity companies		507	-	278	-	1,892	-	2,677
During 2013								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	93	67	-	-	47	-	207
	- Unproved	533	4,270	-	153	-	4	4,960
Exploration costs		557	485	277	361	598	111	2,389
Development costs		6,919	8,527	2,117	3,278	3,493	1,733	26,067
Total costs incurred for consolidated subsidiaries		8,102	13,349	2,394	3,792	4,138	1,848	33,623
Equity Companies								
Property acquisition costs	- Proved	2	-	-	-	-	-	2
	- Unproved	-	-	-	-	17	-	17
Exploration costs		60	-	29	-	494	-	583
Development costs		720	-	192	-	828	-	1,740
Total costs incurred for equity companies		782	-	221	-	1,339	-	2,342
During 2012								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	192	2	95	-	43	-	332
	- Unproved	1,717	74	24	15	-	31	1,861
Exploration costs		601	405	454	520	554	248	2,782
Development costs		7,172	7,601	2,637	3,081	3,347	2,333	26,171
Total costs incurred for consolidated subsidiaries		9,682	8,082	3,210	3,616	3,944	2,612	31,146
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	14	-	-	-	-	-	14
Exploration costs		45	-	34	-	-	-	79
Development costs		504	-	156	-	651	-	1,311
Total costs incurred for equity companies		563	-	190	-	651	-	1,404

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2012, 2013, and 2014.

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

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economical producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations – prior to the time at whic contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. In some cases, substantial new investments in additional wells and relate facilities will 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 change categories shown in the following tables wer calculated using average prices during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-o the-month price for each month within such period. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measu of discounted net cash flow.

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

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

In the proved reserves tables, consolidated reserves and equity company reserves are reported separately. However, the Corporation does not view equity company reserves an differently than those from consolidated companies.

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. Th production and reserves that we report for these types of arrangements typically vary inversely with oil and gas price changes. As oil and gas prices increase, the cash flow and valu received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decreas the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2014 that we associated with production sharing contract arrangements was 11 percent of liquids, 9 percent of natural gas and 10 percent on an oil-equivalent basis (gas converted to oil-equivalent at billion cubic feet = 1 million barrels).

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

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

The changes, between 2013 year-end proved reserves and 2014 year-end proved reserves, primarily reflect the revisions, extensions and discoveries in Canada and the United States.

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.	Total
							(millions of barrels)				
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	10,11
Revisions	25	33	14	20	(10)	5	87	3	265	(29)	32
Improved recovery	6	-	-	-	1	-	7	-	-	-	
Purchases	163	-	20	-	-	-	183	36	-	-	21
Sales	(15)	(1)	(8)	(58)	-	-	(82)	(4)	-	-	(8
Extensions/discoveries	166	138	8	41	9	-	362	164	234	-	76
Production	(100)	(18)	(62)	(173)	(117)	(12)	(482)	(73)	(45)	(25)	(62
December 31, 2012	1,905	270	289	1,293	1,604	163	5,524	1,031	3,560	599	10,71
Proportional interest in proved reserves of equity companies											
January 1, 2012	348	-	29	-	1,255	-	1,632	483	-	-	2,11
Revisions	(2)	-	1	-	131	-	130	15	-	-	14
Improved recovery	16	-	-	-	-	-	16	-	-	-	1
Purchases	-	-	-	-	-	-	-	-	-	-	
Sales	-	-	-	-	-	-	-	-	-	-	
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	
Production	(22)	-	(2)	-	(126)	-	(150)	(24)	-	-	(17
December 31, 2012	340	-	28	-	1,260	-	1,628	474	-	-	2,10
Total liquids proved reserves at December 31, 2012	2,245	270	317	1,293	2,864	163	7,152	1,505	3,560	599	12,81
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	10,71
Revisions	21	20	13	13	411	3	481	(1)	124	4	60
Improved recovery	-	-	-	-	-	-	-	-	-	-	
Purchases	15	15	-	-	-	-	30	27	-	-	5
Sales	(18)	-	-	-	-	-	(18)	(6)	-	-	(2
Extensions/discoveries	188	-	-	52	262	-	502	39	-	-	54
Production	(103)	(21)	(57)	(165)	(114)	(11)	(471)	(67)	(54)	(24)	(61
December 31, 2013	2,008	284	245	1,193	2,163	155	6,048	1,023	3,630	579	11,28
Proportional interest in proved reserves of equity companies											
January 1, 2013	340	-	28	-	1,260	-	1,628	474	-	-	2,10
Revisions	12	-	2	-	21	-	35	8	-	-	4
Improved recovery	-	-	-	-	-	-	-	-	-	-	
Purchases	-	-	-	-	-	-	-	-	-	-	
Sales	-	-	-	-	-	-	-	-	-	-	
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	
Production	(22)	-	(2)	-	(136)	-	(160)	(26)	-	-	(18
December 31, 2013	330	-	28	-	1,145	-	1,503	456	-	-	1,95
Total liquids proved reserves at December 31, 2013	2,338	284	273	1,193	3,308	155	7,551	1,479	3,630	579	13,23

(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.	Total
							(millions of barrels)				
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2014	2,008	284	245	1,193	2,163	155	6,048	1,023	3,630	579	11,28
Revisions	37	23	9	42	42	-	153	59	669	(23)	85
Improved recovery	-	-	-	-	-	-	-	-	-	-	
Purchases	42	-	-	-	-	-	42	11	-	-	5
Sales	(24)	(11)	-	-	(1)	-	(36)	(14)	-	-	(5
Extensions/discoveries	156	5	-	38	35	-	234	79	-	-	31
Production	(111)	(19)	(55)	(171)	(107)	(14)	(477)	(66)	(66)	(22)	(63
December 31, 2014	2,108	282	199	1,102	2,132	141	5,964	1,092	4,233	534	11,82
Proportional interest in proved reserves of equity companies											
January 1, 2014	330	-	28	-	1,145	-	1,503	456	-	-	1,95
Revisions	19	-	1	-	41	-	61	5	-	-	6
Improved recovery	-	-	-	-	-	-	-	-	-	-	
Purchases	1	-	-	-	-	-	1	-	-	-	
Sales	-	-	-	-	-	-	-	-	-	-	
Extensions/discoveries	1	-	-	-	-	-	1	-	-	-	
Production	(23)	-	(2)	-	(86)	-	(111)	(26)	-	-	(13
December 31, 2014	328	-	27	-	1,100	-	1,455	435	-	-	1,89
Total liquids proved reserves at December 31, 2014	2,436	282	226	1,102	3,232	141	7,419	1,527	4,233	534	13,71

(1) Includes total proved reserves attributable to Imperial Oil Limited of 9 million barrels in 2012, 11 million barrels in 2013 and 8 million barrels in 2014, as well as proved developed reserves million barrels in 2012, 9 million barrels in 2013 and 5 million barrels in 2014, and in addition, proved undeveloped reserves of 2 million barrels in 2013 and 3 million in 2014, in which there 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)*	Total
					(millions of barrels)					
Proved developed reserves, as of December 31, 2012										
Consolidated subsidiaries	1,489	124	268	1,004	1,080	116	4,081	543	599	5,223
Equity companies	264	-	28	-	1,423	-	1,715	-	-	1,715
Proved undeveloped reserves, as of December 31, 2012										
Consolidated subsidiaries	921	163	77	497	682	134	2,474	3,017	-	5,491
Equity companies	84	-	-	-	303	-	387	-	-	387
Total liquids proved reserves at December 31, 2012	2,758	287	373	1,501	3,488	250	8,657	3,560	599	12,816
Proved developed reserves, as of December 31, 2013										
Consolidated subsidiaries	1,469	126	249	945	1,663	105	4,557	1,810	579	6,946
Equity companies	268	-	27	-	1,292	-	1,587	-	-	1,587
Proved undeveloped reserves, as of December 31, 2013										
Consolidated subsidiaries	1,068	177	51	449	638	131	2,514	1,820	-	4,334
Equity companies	77	-	1	-	294	-	372	-	-	372
Total liquids proved reserves at December 31, 2013	2,882	303	328	1,394	3,887	236	9,030	3,630	579	13,239
Proved developed reserves, as of December 31, 2014										
Consolidated subsidiaries	1,502	111	205	894	1,615	112	4,439	2,122	534	7,095
Equity companies	269	-	26	-	1,188	-	1,483	-	-	1,483
Proved undeveloped reserves, as of December 31, 2014										
Consolidated subsidiaries	1,234	190	42	401	651	99	2,617	2,111	-	4,728
Equity companies	75	-	1	-	331	-	407	-	-	407
Total liquids proved reserves at December 31, 2014	3,080	301	274	1,295	3,785	211	8,946 *(4)*	4,233	534	13,713

(1) Includes total proved reserves attributable to Imperial Oil Limited of 53 million barrels in 2012, 62 million barrels in 2013 and 46 million barrels in 2014, as well as proved developed reserves o million barrels in 2012, 55 million barrels in 2013 and 36 million barrels in 2014, and in addition, proved undeveloped reserves of 1 million barrels in 2012, 7 million barrels in 2013 and 10 mil barrels in 2014, in which there is a 30.4 percent noncontrolling interest.

(2) Includes total proved reserves attributable to Imperial Oil Limited of 2,841 million barrels in 2012, 2,867 million barrels in 2013 and 3,274 million barrels in 2014, as well as proved develo reserves of 543 million barrels in 2012, 1,417 million barrels in 2013 and 1,635 million barrels in 2014, and in addition, proved undeveloped reserves of 2,298 million barrels in 2012, 1,450 mil barrels in 2013 and 1,639 million barrels in 2014, in which there is a 30.4 percent noncontrolling interest.

(3) Includes total proved reserves attributable to Imperial Oil Limited of 599 million barrels in 2012, 579 million barrels in 2013 and 534 million barrels in 2014, as well as proved developed reserve 599 million barrels in 2012, 579 million barrels in 2013 and 534 million barrels in 2014, in which there is a 30.4 percent noncontrolling interest.

(4) See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional information on natural gas liquids proved reserves see I 2. Properties in ExxonMobil's 2014 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent Total All Products (2)
	United States	Canada/ South Amer. (1)	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrel*
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
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

(See footnotes on next page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Total All Products *(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrel*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2014	26,020	1,235	2,810	867	5,734	7,515	44,181	18,644
Revisions	49	80	49	(21)	173	(38)	292	906
Improved recovery	-	-	-	-	-	-	-	-
Purchases	60	-	-	-	-	-	60	63
Sales	(314)	(48)	-	-	(3)	-	(365)	(111)
Extensions/discoveries	1,518	91	-	7	4	-	1,620	583
Production	(1,346)	(132)	(476)	(42)	(448)	(201)	(2,645)	(1,072)
December 31, 2014	25,987	1,226	2,383	811	5,460	7,276	43,143	19,013
Proportional interest in proved reserves of equity companies								
January 1, 2014	281	-	8,884	-	18,514	-	27,679	6,572
Revisions	5	-	117	-	110	-	232	105
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	1
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	1
Production	(15)	-	(583)	-	(1,119)	-	(1,717)	(423)
December 31, 2014	272	-	8,418	-	17,505	-	26,195	6,256
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,269

(1) Includes total proved reserves attributable to Imperial Oil Limited of 488 billion cubic feet in 2012, 678 billion cubic feet in 2013 and 627 billion cubic feet in 2014, as well as pro developed reserves of 374 billion cubic feet in 2012, 368 billion cubic feet in 2013 and 300 billion cubic feet in 2014, and in addition, proved undeveloped reserves of 114 billion cu feet in 2012, 310 billion cubic feet in 2013 and 327 billion cubic feet in 2014, 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							Oil-Equivalent Total All Products (2)
	United States	Canada/ South Amer. (1)	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrel.*
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
Proved developed reserves, as of December 31, 2014								
Consolidated subsidiaries	14,169	615	1,870	764	5,031	2,179	24,628	11,199
Equity companies	194	-	6,484	-	16,305	-	22,983	5,314
Proved undeveloped reserves, as of December 31, 2014								
Consolidated subsidiaries	11,818	611	513	47	429	5,097	18,515	7,814
Equity companies	78	-	1,934	-	1,200	-	3,212	942
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,269

(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 computed by applying first-day-of-the-month average price year-end costs and legislated tax rates and a discount factor of 10 percent to net proved reserves. The standardized measure includes costs for future dismantlement, abandonment ar rehabilitation obligations. The Corporation believes the standardized measure does not provide a reliable estimate of the Corporation's expected future cash flows to be obtained from th development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescrib assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year a prices change.

Standardized Measure of Discounted Future Cash Flows	United States	Canada/ South America *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	250,382	293,910	66,769	160,261	192,491	104,334	1,068,14
Future production costs	109,325	101,299	17,277	33,398	42,816	26,132	330,24
Future development costs	37,504	44,518	16,505	13,363	13,083	11,435	136,40
Future income tax expenses	43,772	34,692	23,252	63,246	75,261	21,405	261,62
Future net cash flows	59,781	113,401	9,735	50,254	61,331	45,362	339,86
Effect of discounting net cash flows at 10%	36,578	82,629	2,097	18,091	35,310	27,610	202,31
Discounted future net cash flows	23,203	30,772	7,638	32,163	26,021	17,752	137,54
Equity Companies							
As of December 31, 2012							
Future cash inflows from sales of oil and gas	36,043	-	93,563	-	348,026	-	477,63
Future production costs	7,040	-	64,988	-	112,980	-	185,00
Future development costs	3,708	-	2,569	-	10,780	-	17,05
Future income tax expenses	-	-	9,937	-	78,539	-	88,47
Future net cash flows	25,295	-	16,069	-	145,727	-	187,09
Effect of discounting net cash flows at 10%	14,741	-	8,133	-	76,979	-	99,85
Discounted future net cash flows	10,554	-	7,936	-	68,748	-	87,23
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	224,78

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

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ South America (1)	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2013							
Future cash inflows from sales of oil and gas	276,051	293,377	58,235	146,407	245,482	87,808	1,107,360
Future production costs	113,571	106,884	18,053	30,960	57,328	22,507	349,303
Future development costs	40,702	43,102	15,215	14,300	10,666	10,191	134,176
Future income tax expenses	50,144	31,901	17,186	53,766	117,989	16,953	287,939
Future net cash flows	71,634	111,490	7,781	47,381	59,499	38,157	335,942
Effect of discounting net cash flows at 10%	42,336	78,700	1,278	18,406	34,878	21,266	196,864
Discounted future net cash flows	29,298	32,790	6,503	28,975	24,621	16,891	139,078
Equity Companies							
As of December 31, 2013							
Future cash inflows from sales of oil and gas	34,957	-	82,539	-	324,666	-	442,162
Future production costs	8,231	-	60,518	-	107,656	-	176,405
Future development costs	3,675	-	2,994	-	8,756	-	15,425
Future income tax expenses	-	-	7,237	-	70,887	-	78,124
Future net cash flows	23,051	-	11,790	-	137,367	-	172,208
Effect of discounting net cash flows at 10%	12,994	-	5,549	-	72,798	-	91,341
Discounted future net cash flows	10,057	-	6,241	-	64,569	-	80,867
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	219,945
Consolidated Subsidiaries							
As of December 31, 2014							
Future cash inflows from sales of oil and gas	283,767	354,223	42,882	125,125	224,885	78,365	1,109,247
Future production costs	116,929	140,368	14,358	27,917	57,562	20,467	377,601
Future development costs	42,276	48,525	13,000	14,603	12,591	8,956	139,951
Future income tax expenses	49,807	36,787	10,651	44,977	102,581	15,050	259,853
Future net cash flows	74,755	128,543	4,873	37,628	52,151	33,892	331,842
Effect of discounting net cash flows at 10%	44,101	87,799	(52)	13,831	30,173	17,326	193,178
Discounted future net cash flows	30,654	40,744	4,925	23,797	21,978	16,566	138,664
Equity Companies							
As of December 31, 2014							
Future cash inflows from sales of oil and gas	31,924	-	71,031	-	286,124	-	389,079
Future production costs	8,895	-	50,826	-	99,193	-	158,914
Future development costs	3,386	-	2,761	-	11,260	-	17,407
Future income tax expenses	-	-	6,374	-	59,409	-	65,783
Future net cash flows	19,643	-	11,070	-	116,262	-	146,975
Effect of discounting net cash flows at 10%	10,970	-	5,534	-	61,550	-	78,054
Discounted future net cash flows	8,673	-	5,536	-	54,712	-	68,921
Total consolidated and equity interests in standardized measure of discounted future net cash flows	39,327	40,744	10,461	23,797	76,690	16,566	207,585

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $25,160 million in 2013 and $30,189 million in 2014, in which there is a 30.4 percent noncontrol interest.

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

Consolidated and Equity Interests	**2012**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2011	152,244	86,560	238,804
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	7,952	531	8,483
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)	(74,774)
Development costs incurred during the year	24,596	1,186	25,782
Net change in prices, lifting and development costs	(31,382)	5,656	(25,726)
Revisions of previous reserves estimates	3,876	7,018	10,894
Accretion of discount	19,676	8,846	28,522
Net change in income taxes	12,339	463	12,802
Total change in the standardized measure during the year	(14,695)	678	(14,017)
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,787

Consolidated and Equity Interests	**2013**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(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

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

Consolidated and Equity Interests (continued)	2014		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2013	139,078	80,867	219,945
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	3,497	94	3,591
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	(44,446)	(18,366)	(62,812)
Development costs incurred during the year	24,189	1,453	25,642
Net change in prices, lifting and development costs	(50,672)	(13,165)	(63,837)
Revisions of previous reserves estimates	35,072	3,298	38,370
Accretion of discount	20,098	8,987	29,085
Net change in income taxes	11,848	5,753	17,601
Total change in the standardized measure during the year	(414)	(11,946)	(12,360)
Discounted future net cash flows as of December 31, 2014	138,664	68,921	207,585

OPERATING SUMMARY (unaudited)

	2014	2013	2012	2011	2010
Production of crude oil, natural gas liquids, bitumen and synthetic oil					
Net production			*(thousands of barrels daily)*		
United States	454	431	418	423	408
Canada/South America	301	280	251	252	263
Europe	184	190	207	270	335
Africa	489	469	487	508	628
Asia	624	784	772	808	730
Australia/Oceania	59	48	50	51	58
Worldwide	2,111	2,202	2,185	2,312	2,422
Natural gas production available for sale					
Net production			*(millions of cubic feet daily)*		
United States	3,404	3,545	3,822	3,917	2,596
Canada/South America	310	354	362	412	569
Europe	2,816	3,251	3,220	3,448	3,836
Africa	4	6	17	7	14
Asia	4,099	4,329	4,538	5,047	4,801
Australia/Oceania	512	351	363	331	332
Worldwide	11,145	11,836	12,322	13,162	12,148
			(thousands of oil-equivalent barrels daily)		
Oil-equivalent production *(1)*	3,969	4,175	4,239	4,506	4,447
Refinery throughput			*(thousands of barrels daily)*		
United States	1,809	1,819	1,816	1,784	1,753
Canada	394	426	435	430	444
Europe	1,454	1,400	1,504	1,528	1,538
Asia Pacific	628	779	998	1,180	1,249
Other Non-U.S.	191	161	261	292	269
Worldwide	4,476	4,585	5,014	5,214	5,253
Petroleum product sales *(2)*					
United States	2,655	2,609	2,569	2,530	2,511
Canada	496	464	453	455	450
Europe	1,555	1,497	1,571	1,596	1,611
Asia Pacific and other Eastern Hemisphere	1,085	1,206	1,381	1,556	1,562
Latin America	84	111	200	276	280
Worldwide	5,875	5,887	6,174	6,413	6,414
Gasoline, naphthas	2,452	2,418	2,489	2,541	2,611
Heating oils, kerosene, diesel oils	1,912	1,838	1,947	2,019	1,951
Aviation fuels	423	462	473	492	476
Heavy fuels	390	431	515	588	603
Specialty petroleum products	698	738	750	773	773
Worldwide	5,875	5,887	6,174	6,413	6,414
Chemical prime product sales *(3)*			*(thousands of metric tons)*		
United States	9,528	9,679	9,381	9,250	9,815
Non-U.S.	14,707	14,384	14,776	15,756	16,076
Worldwide	24,235	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, petroleum product and chemical prime product sal include ExxonMobil's ownership percentage and refining throughput includes quantities processed for ExxonMobil. Net production excludes royalties and quantities due others whe 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 are total product sales excluding carbon black oil and sulfur. Prime product sales include ExxonMobil's share of equity company volumes and finished-prod 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 caused this report to be signed on its behalf by th undersigned, thereunto duly authorized.

EXXON MOBIL CORPORATION

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

Dated February 25, 2015

POWER OF ATTORNEY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in th capacities indicated and on February 25, 2015.

/s/ REX W. TILLERSON (Rex W. Tillerson)	Chairman of the Board (Principal Executive Officer)
/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/ ANDREW P. SWIGER (Andrew P. Swiger)	Senior Vice President (Principal Financial Officer)
/s/ DAVID S. ROSENTHAL (David S. Rosenthal)	Vice President and Controller (Principal Accounting Officer)

INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to th Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 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-K on 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) to the Registrant's Annual Report on Form 10-I for 2012).*
10(iii)(a.2)	Extended Provisions for Restricted Stock Agreements (incorporated by reference to Exhibit 99.2 to the Registrant's Report on 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 (incorporated by reference to Exhibit 10(iii)(a.4) to the Registrant's Annual Report c Form 10-K for 2013).*
10(iii)(b.1)	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 10(iii)(b.1) to the Registrant's Annual Report on Form 10-K for 2013).*
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 (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant's Annual Report on Form 10-K for 2013).*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Registrant's Annual Report on Form 10-K fo 2011).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f.1) to the Registrant's Annual Report on Form 10-K for 2013).*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by reference to Exhibit 10(iii)(f.2) to the Registrant's Quarterl 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.*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated October 26, 2011 (incorporated by reference to Exhibit 10(iii)(f.4) to the Registrant's Quarterly Report c 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 Registrant's Annual Report on Form 10-K for 2011).*
12	Computation of ratio of earnings to fixed charges.
14	Code of Ethics and Business Conduct (incorporated by reference to Exhibit 14 to the Registrant's Annual Report on Form 10-K for 2013).
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 and its subsidiaries for which consolidated or unconsolidated financial statements are required to be filed. The registrant agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon request.

EXHIBIT 10(iii)(a.

November 25, 20.

Exxon Mobil Corporation

Extended Provisions for Restricted Stock Unit Agreements - Settlement in Shares

1. **Effective Date and Credit of Restricted Stock Units.** If Grantee accepts the award on or before March 6, 2015, this Agreement will become effective the date the Corporation receives the award acceptance. After this agreement becomes effective, the Corporation will credit to Grantee the number of restricted stock units specified in the award packag Subject to the terms and conditions of this Agreement, each restricted stock unit ("unit") will entitle Granteeto receive in settlement of the unit one share of the Corporation's common stock.

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

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

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

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

   a) with respect to 50% of the units, on November 25, 2019; and
   b) with respect to the remaining units, on the later to occur of
      (i) November 25, 2024, or
      (ii) the first day of the calendar year immediately following the year in which Grantee terminates; except that
   c) the restricted periods will automatically expire with respect to all shares on the death of Grantee.

5. **No Obligation to Credit Units .** The Corporation will have no obligation to credit any units and will have no other obligation to Grantee with respect to the subject matter o this Agreement if Grantee fails to accept the award on or before March 6, 2015. In addition, whether or not Grantee has accepted the award, the Corporation will have no obligation to credit any units and will have no other obligation to Grantee with respect to the subject matter of this Agreement if, before the units are credited:

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

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

Termination

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

Detrimental activity

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

Attempted transfer

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

Applicable law

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

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

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

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

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

provisions, restrictions, and requirements as those previously credited units.

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

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

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

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

15. **Transfer of Personal Data.** The administration of the Program and this Agreement, including any subsequent ownership of shares, involve the collection, use, and transfer of personal data about Grantee between and among the Corporation, selected subsidiaries and other affiliates of the Corporation, and third-party service providers such as Morgan Stanley and Computershare (the Corporation's transfer agent), as well as various regulatory and tax authorities around the world. This data includes Grantee's name, age, date c birth, contact information, work location, employment status, tax status, social security number, salary, nationality, job title, share ownership, and details of incentive awards granted, cancelled, vested or unvested, and related information. By accepting this award, Grantee authorizes such collection, use, and transfer of this data. Grantee may, at any time and without charge, view such data and require necessary corrections to it. Such data will at all times be held in accordance with applicable laws, regulations, and agreements.

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

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

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

EXHIBIT 10(iii)(b.

EXXON MOBIL CORPORATION

EARNINGS BONUS UNIT AWARD

EBU Number	Name of Grantee	Number of EBUs	Maximum Settlement Value Per EBU	Maximum Settlement Value of Award
			$6.50	

This **EARNINGS BONUS UNIT AWARD** is granted in Dallas County, Texas by Exxon Mobil Corporation (the "Corporation") effective November 25, 2014 (the "date of grant"), pursuant to the Short Term Incentive Program adopted by the Board of Directors of the Corporation on October 27, 1993, as amended (the "Program"). This award is subject to the provisions of this instrument and the Program and to such regulations and requirements as may be stipulated from time t time by the administrative authority defined in the Program and is granted on the condition that Grantee accepts such provisions, regulations and requirements. This instrument incorporates by reference the provisions of the Program, as it may be amended from time to time, including without limitation the definitions of terms used in this instrument and defined in the Program.

1. Award. The Corporation has granted to Grantee the number of earnings bonus units ("EBUs") set forth above, with each EBU having the maximum settlement value set forth above. Subject to the other terms of this award, Grantee has the right, for each of these EBUs, to receive from the Corporation, promptl after the settlement date defined below, an amount of cash equal to the Corporation's cumulative earnings per common share (assuming dilution) as reflected in it quarterly earnings statements as initially filed in its quarterly or annual reports with the U.S. Securities and Exchange Commission commencing with earnings fo the first full quarter following the date of grant to and including the last full quarter preceding the settlement date; provided, however, that the amount of such settlement will not exceed the maximum settlement value specified above.

2. Settlement Date. The settlement date of these EBUs will be the earlier of (i) the date of publication of the Corporation's quarterly earnings statement for the twelfth (12th) full quarter following the date of grant, or (ii) the date of publication of the Corporation's quarterly earnings statement which brings the cumulative earnings per common share (assuming dilution) as initially filed in its quarterly or annual reports with the U.S. Securities and Exchange Commission commencin with the first full quarter following the date of grant to an amount at least equal to the maximum settlement value per EBU specified above.

3. Annulment. This award is provisional until the Corporation actually pays cash in settlement of the award.

(a) If, before the Corporation pays such cash, Grantee terminates (other than by death) before standard retirement time within the meaning of the Program, thi award will automatically expire as of the date of termination, except to the extent the administrative authority determines Grantee may retain this award.

(b) If, before the Corporation pays such cash, Grantee is determined to have engaged in detrimental activity within the meaning of the Program, this award wi automatically expire as of the date of such determination.

4. Adjustments. The number of EBUs covered by this award and the meaning of the term "common share" will be adjusted by the administrative authority as it deems appropriate to give effect to any stock split, stock dividend or other relevant change in capitalization of the Corporation after the date of grant and prior to the settlement date.

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

EXXON MOBIL CORPORATION

EXHIBIT 10(iii)(c.

EXXONMOBIL SUPPLEMENTAL SAVINGS PLAN
(including Key Employee Supplemental Savings Plan)
Effective January 1, 2015

1. Purpose

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

2. Benefits

2.1 Eligibility

A person is eligible to receive benefits under this Plan only if the person satisfies any of the following requirements:

(A) The person becomes a retiree pursuant to section 4.1(A) (relating to age, service and LTD-eligibility requirements) or section 4.1(D) (relating to retiree grow-ins connection with certain divestments) of the ExxonMobil Common Provisions; or

(B) The person becomes a qualified plans retiree within the meaning of the ExxonMobil Pension Plan.

2.2 Benefit Formula

(A) In General

As to any specific Savings Plan participant the total amount of payment under this Plan is an amount that is in general determined by notionally crediting on a mon basis the amount of employer contributions that cannot be made to the Savings Plan for that person as a result of application to that person of Code sections 415 and 40 (17); except that, for those persons who, as of December 31, 1993, are classified at level 36 and are age 50 and above, only notional employer contributions made a such date are taken into account. This amount is enhanced in each instance by 120 percent of the long-term Applicable Federal Rate, compounded monthly, as of the month of each calendar quarter as published by the Internal Revenue Service, and is then reduced, but not below zero, by the amount, if any, of the actuarial lump-s value of the amount payable to the participant under the ExxonMobil Key Employee Additional Payments Plan that is not applied as an offset against the participa benefit under the ExxonMobil Additional Payments Plan or the ExxonMobil Supplemental Pension Plan. For this purpose, the actuarial lump-sum value shall determined using the mortality and interest rate assumptions set out in the ExxonMobil Pension Accounts Instrument.

(B) Notional Interest Rate for Key Employees after Termination or Retirement

As to a participant who, immediately prior to his or her termination or retirement, has a Classification Level of 36 or above ("Key Employee"), "120 percent of the lo term Applicable Federal Rate, compounded monthly, as of the last month of each calendar quarter as published by the Internal Revenue Service" in paragraph (A) ab shall be replaced with "Citibank Prime Lending Rate as of the last business day of each calendar quarter" for the period between date of termination or retirement and of payment.

2.3 Calculation Methodology

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

(A) Required Participant Contributions

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

(B) Discretionary Employee Contributions

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

3. Payment of Benefits

Payment of the benefit determined under article 2 above shall be made in a lump sum as soon as practicable following the latest of the following times:

(A) the participant's retirement from ExxonMobil;

(B) In the case of a Key Employee, the six-month anniversary of the participant's termination of employment or retirement;

(C) In the case of a participant whose Savings Plan account is transferred to a savings plan sponsored by Infineum USA Inc. or any of its affiliates ("Infineum"), participant's termination of employment from Infineum; or

(D) In the case of a participant whose Savings Plan account is transferred to a savings plan sponsored by Tenneco, Inc. or any of its affiliates ("Tenneco"), the participan termination of employment from Tenneco.

4. Payment Upon Death

4.1 In General

If a person dies as an employee with eligibility for a pension death benefit under the ExxonMobil Pension Plan or as a retiree but before his benefit under this Plan is distribute him, then such benefit shall be distributed as soon as practicable after death to the person's beneficiary determined under section 4.2 below.

4.2 Designation of Beneficiaries

(A) In General

A person entitled to receive a payment under this Plan may name one or more designated beneficiaries to receive such payment in the event of the pers death. Beneficiary designations shall be made in accordance with such procedures as the Plan Administrator may establish. Spousal consent to any designation is required.

(B) Default Beneficiaries

(1) In General

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

(a) spouse;

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

(c) parents;

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

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

(2) Allocation among Default Beneficiaries

If the same class of beneficiaries under paragraph (1) above contains two or more persons, they share equally, with further subdivision of such equal shares next provided. In class (b), where a child dies before the participant leaving children who survive the participant, such child's share is subdivided equally am those children. In class (d), where a brother or sister dies before the participant leaving children who survive the participant, such brother or sister's shar subdivided equally among those children.

(3) Definitions

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

5. Miscellaneous

5.1 Administration of Plan

The Plan Administrator shall be the Manager, Compensation, Benefit Plans and Policies, Human Resources Department, Exxon Mobil Corporation. The Plan Administrator sh have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person's eligibility for benefits hereunder and the resolutio any and all appeals relating to claims by participants or beneficiaries, with any such interpretation being conclusive for all participants and beneficiaries.

5.2 Nature of Payments

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

5.3 Assignment or Alienation

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

5.4 Amendment or Termination

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

5.5 Forfeiture of Benefits

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

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

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

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

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

(E) had been terminated for cause.

EXXONMOBIL KEY EMPLOYEE SUPPLEMENTAL SAVINGS PLAN

K1. Purpose

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

(A) was classified at level 36 or above,

(B) was age 50 or above,

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

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

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

K2. Benefits

K2.1 Benefit Formula

(A) In General

As to a participant, the total amount of payment under this Plan shall be an amount that has been in general determined by notionally crediting on a monthly basis amount of employer contributions that could not have been made to the Thrift Plan account of that person as a result of application to that person of Code sections 415 401(a)(17) from the date the person otherwise would have been an eligible participant in the Exxon Supplemental Thrift Plan until December 30, 1993. This amount s be enhanced in each instance by 120 percent of the long-term Applicable Federal Rate, compounded monthly, as of the last month of each calendar quarter as published the Internal Revenue Service. A participant in this Plan shall have a non-forfeitable right to this amount credited as of December 31, 1993 plus all enhancements.

(B) Notional Interest Rate for Key Employees after Termination or Retirement

As to a participant who, immediately prior to his or her termination or retirement, has a Classification Level of 36 or above, "120 percent of the long-term Applica Federal Rate, compounded monthly, as of the last month of each calendar quarter as published by the Internal Revenue Service" in paragraph (A) above shall be repla with "Citibank Prime Lending Rate as of the last business day of each calendar quarter" for the period between date of termination or retirement and date of payment.

K2.2 Calculation Methodology

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

K3. Payment of Benefits

K3.1 Form of Payment

Payments under this Plan are made in the form of a lump sum single payment.

K3.2 Timing of Payment

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

K4. Beneficiaries

K4.1 Designation of Beneficiaries

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

K4.2 Default Beneficiaries

(A) In General

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

(1) spouse;
(2) children who survive the participant or who die before the participant leaving children of their own who survive the participant;
(3) parents;
(4) brothers and sisters who survive the participant or who die before the participant leaving children of their own who survive the participant.

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

(B) Allocation among Default Beneficiaries

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

(C) Definitions

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

K5. Miscellaneous

K5.1 Administration of Plan

The Plan Administrator shall be the Manager, Compensation, Benefit Plans and Policies, Human Resources Department, ExxonMobil Corporation. The Plan Administrator sh have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person's eligibility for benefits hereunder and the resolutio any and all appeals relating to claims by participants or beneficiaries, with any such interpretation being conclusive for all participants and beneficiaries.

K5.2 Nature of Payments

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

K5.3 Assignment or Alienation

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

K5.4 Amendment or Termination

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

EXHIBIT 10(iii)(c.

EXXONMOBIL SUPPLEMENTAL PENSION PLAN
(Including Key Employee Supplemental Pension Plan)
Effective January 1, 2015

1. Purpose

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

2. Benefits

2.1 Eligibility

A person is eligible to receive benefits under this Plan only if the person satisfies any of the following requirements:

(A) The person becomes a retiree pursuant to section 4.1(A) (relating to age, service and LTD-eligibility requirements) or section 4.1(D) (relating to retiree grow-ins connection with certain divestments) of the ExxonMobil Common Provisions; or

(B) The person becomes a qualified plans retiree within the meaning of the ExxonMobil Pension Plan.

2.2 Benefit Formula

(A) In General

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

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

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

Where relevant, this computation is performed after taking into account any entitlement the participant may have under the Overseas Contributory Annuity Plan. resulting benefit is expressed in the form of a monthly five-year-certain and life annuity for the life of the participant commencing at the participant's age 65 ("Nor Retirement Age").

(B) Benefit Formula for Former Mobil Employee

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

(1) In General

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

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

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

expressed in the form of a monthly five-year-certain and life annuity for the life of the participant commencing at the participant's Normal Retirement Age.

(2) Nonqualified PSSP Benefits

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

2.3 Offsets for Other Pension Benefits
A person's benefit determined under section 2.2 shall be offset, but not below zero, by any benefit payable to the person under (A) an offsetting pension that is not qualified un the terms of the U.S. Internal Revenue Code, (B) a separation payment offset, or (C) a non-U.S. governmental pension offset, as such terms are defined under the ExxonM Pension Plan.

2.4 Plan Administrator Discretion
The procedure for calculating the benefit for former Mobil employees under section 2.2 above, and for determining the application of the offsets for other pension benefits un section 2.3 above, shall be determined in the sole and exclusive discretion of the Plan Administrator.

3. Payment of Benefits

3.1 Timing of Payment
(A) In General
Except as provided in paragraph (B) or (C) below, payment of the benefit described in article 2 above shall occur as soon as practicable following the later to occur of following:
(1) the person's retirement from ExxonMobil;
(2) in the case of a person who, immediately prior to his or her retirement, has a Classification Level of 36 or above ("Key Employee"), the six-month annivers of the person's retirement;
(B) Retirement Prior to Age 55
In the case of a person who retires from ExxonMobil on account of long-term disability prior to the first of the month in which the person attains age 55, payment of benefit described in article 2 above shall occur on the first of the month in which the person attains age 55, or as soon as practicable thereafter.

3.2 Reduction for Early Commencement
If payments under this Plan commence prior to the month in which the person reaches Normal Retirement Age, they are reduced by applying the early commencement fact specified under the Pension Plan for a benefit commencing at the person's then age.

3.3 Form of Payment
Payment of the benefit described in article 2 above shall be made in a lump sum that is the actuarial equivalent of the five-year-certain and life annuity calculated under sect 2.2(A) or 2.2(B)(1) or the actuarial equivalent of the PSSP benefit calculated under 2.2(B)(2). For this purpose, actuarial equivalence shall be determined by the Plan Administra using the factors and procedures that are used for the calculation of the lump-sum payment option under the Pension Plan.

3.4 Adjustment for Key Employees
If payment of a Key Employee's benefit is delayed for six months following termination or retirement because of the requirement set out in section 3.1(A)(2) above, then insteac the lump-sum benefit calculated under section 3.3 above, the person shall receive a lump-sum benefit equal to the greater of the following:
(A) The lump-sum payment that would otherwise have been calculated for the person under section 3.3 above as if he were not a Key Employee, based on the payment c that would have applied to the individual if he were not a Key employee and on the actuarial factors applicable as of such date under the ExxonMobil Pension Plan, p interest for the period of delayed payment; or
(B) A lump-sum that is the actuarial equivalent of the person's five-year-certain and life annuity calculated as of the delayed payment date and using the actuarial fact applicable as of the six-month anniversary of the person's retirement date.
Interest shall be credited under paragraph (A) above, at a rate equal to the Citibank prime lending rate in effect on the date the person separates from employment.

4. Death Benefit

4.1 Benefits Payable On Account of Death

(A) In General

In the event a portion of a pension death benefit or a "career annuity subject to deferred commencement that commences by reason of death" that becomes payable ur the terms of the Pension Plan on account of the death of a participant cannot be paid from the Pension Plan because of the application of Code sections 415 and 401(a)(a lump-sum death benefit of equivalent value shall be paid to the participant's beneficiary (as determined under section 4.2 below) under this Plan. For this purpo equivalent value shall be determined by the Plan Administrator using the factors and procedures that are used for the calculation of similar benefits under the Pension P

(B) Excluded Benefits

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

4.2 Designation of Beneficiaries

(A) In General

A person may name one or more designated beneficiaries to receive the benefits payable under this Plan under section 4.1 above in the event of the person's de Beneficiary designations shall be made in accordance with such procedures as the Plan Administrator may establish. Spousal consent to any designation is not required.

(B) Default Beneficiaries

(1) In General

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

(a) spouse;
(b) children who survive the participant or who die before the participant leaving children of their own who survive the participant;
(c) parents;
(d) brothers and sisters who survive the participant or who die before the participant leaving children of their own who survive the participant.

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

(2) Allocation among Default Beneficiaries

If the same class of beneficiaries under paragraph (1) above contains two or more persons, they share equally, with further subdivision of such equal shares next provided. In class (b), where a child dies before the participant leaving children who survive the participant, such child's share is subdivided equally am those children. In class (d), where a brother or sister dies before the participant leaving children who survive the participant, such brother or sister's shar subdivided equally among those children.

(3) Definitions

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

5. Miscellaneous

5.1 Administration of Plan

The Plan Administrator shall be the Manager, Compensation, Benefit Plans and Policies, Human Resources Department, Exxon Mobil Corporation. The Plan Administrator sh have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person's eligibility for benefits hereunder and the resolution any and all appeals relating to claims by participants or beneficiaries, with any such interpretation being conclusive for all participants and beneficiaries.

5.2 Nature of Payments

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

5.3 Assignment or Alienation

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

5.4 Amendment or Termination

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

5.5 Forfeiture of Benefits

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

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

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

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

(D) separated from service prior to attaining Normal Retirement Age without having received from the Corporation or its delegatee prior written approval for s termination, given in the sole discretion of the Corporation or its delegatee and in the context of recognition that benefits under this Plan would not be forfeited upon s termination, or

(E) had been terminated for cause.

KEY EMPLOYEE SUPPLEMENTAL PENSION PLAN

K1. Purpose

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

(A) were classified at level 36 or above,

(B) were age 50 and above, and

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

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

K2. Benefits

K2.1 Benefit Formula

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

K2.2 Benefit Payable On Account of Death

(A) Death Benefit

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

(B) Deferred Annuity Death Benefit

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

(C) Calculation Methodology

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

(D) Excluded Benefits

Specifically excluded from coverage and entitlement under this Plan are:

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

(2) the right to elect a Surviving Spouse Annuity

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

K3. Beneficiaries

K3.1 Designation of Beneficiaries

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

K3.2 Default Beneficiaries

(A) In General

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

(1) spouse;
(2) children who survive the participant or who die before the participant leaving children of their own who survive the participant;
(3) parents;
(4) brothers and sisters who survive the participant or who die before the participant leaving children of their own who survive the participant.

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

(B) Allocation among Default Beneficiaries

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

(C) Definitions

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

K4. Payment of Benefits

K4.1 Commencement of Benefits

(A) In General

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

(B) Reduction for Early Commencement

If payments under this Plan commence prior to the month in which the person reaches age 65, they are reduced by applying the early commencement factors for retir set forth in the Pension Plan for a normal maturity age of 65. For all actuarial purposes, this monthly amount paid as a five-year certain life annuity is deemed the nor form amount.

K4.2 Form of Payment

Payments under this Plan shall be made in the form of a lump sum that is the actuarial equivalent of the five-year-certain and life annuity in which the normal form of benef expressed. For this purpose, actuarial equivalency shall be determined by the Plan Administrator using the factors used for comparable determinations under the Pension Plan.

K5. Miscellaneous

K5.1 Administration of Plan

The Plan Administrator shall be the Manager, Compensation, Benefit Plans and Policies, Human Resources Department, ExxonMobil Corporation. The Plan Administrator sh have the right and authority to conclusively interpret this Plan for all purposes, including the determination of any person’s eligibility for benefits hereunder and the resolution any and all appeals relating to claims by participants or beneficiaries, with any such interpretation being conclusive for all participants and beneficiaries.

K5.2 Nature of Payments

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

K5.3 Assignment or Alienation

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

K5.4 Amendment or Termination

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

EXHIBIT 10(iii)(f.

Exxon Mobil Corporation

5959 Las Colinas Boulevard

Irving, TX 75039

Jeffrey J. Woodbury

Vice President, Investor Relations

and Secretary

January 2, 2015

[Name of Non-Employee Director]

I am pleased to inform you that on January 2, 2015, you were granted 2,500 shares of restricted stock under Exxon Mobil Corporation's 2004 Non-Employee Director Restricted Stock Plan (the "Plan") and in accordance with the Board's standing resolution regarding grants under the Plan. This letter summarizes key terms of your award and is qualified by reference to the Plan. You should refer to the text of the Plan for a detailed description of the terms and conditions of your award. Copies of the Plan have been previously distributed to you and are also available on request to me at any time.

The restricted stock has been registered in your name and will be held in book-entry form by the Corporation's agent during the restricted period. As the owner of record, you have the right to vote the shares and receive cash dividends. However, during the restricted period the shares may not be sold, assigned, transferred, pledged, or otherwise disposed of or encumbered, and your restricted stock account will be subject to stop transfer instructions.

The restricted period for this award began at the time of grant. The restricted period will expire when you leave the Board after reaching retirement age (currently, age 72) or by reason o death. If you leave the Board before reaching retirement age, your restricted stock will be forfeited unless the Board determines to lift the restrictions at that time.

If and when the restricted period expires, shares will be delivered to or for your account free of restrictions.

You are entitled to designate a beneficiary for your restricted stock account. Please contact Jerry Miller at (972) 444-4004 for the necessary form should you wish to do so.

By accepting this award you agree to all its terms and conditions, including the restrictions on transfer and events of forfeiture.

Additional information concerning your award, including information on the tax consequences of your award and certain additional information required by the Securities Act of 1933, is also enclosed with this letter.

Any questions that you may have concerning the Plan or this award should be addressed to me.

Sincerely,

[signed by Jeffrey J. Woodbury]

Enclosures

EXHIBIT 1

EXXON MOBIL CORPORATION

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2014	2013	2012	2011	2010
			(millions of dollars)		
Income from continuing operations attributable to ExxonMobil	32,520	32,580	44,880	41,060	30,46
Excess/(shortfall) of dividends over earnings of affiliates accounted for by the equity method	(358)	3	(1,157)	(273)	(59
Provision for income taxes	18,015	24,263	31,045	31,051	21,56
Capitalized interest	121	148	(67)	(159)	(12
Noncontrolling interests in earnings of consolidated subsidiaries	1,095	868	2,801	1,146	93
	51,393	57,862	77,502	72,825	52,23
Fixed Charges:					
Interest expense - borrowings	157	137	117	77	2
Capitalized interest	344	309	506	593	53
Rental cost representative of interest factor	618	612	640	721	70
	1,119	1,058	1,263	1,391	1,26
Total adjusted earnings available for payment of fixed charges	52,512	58,920	78,765	74,216	53,50
Number of times fixed charges are earned	46.9	55.7	62.4	53.4	42.

EXHIBIT 2

Subsidiaries of the Registrant (1), (2) and (3) – at December 31, 2014

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Abu Dhabi Petroleum Company Limited (5)	23.75	United Kingdom
Aera Energy LLC (5)	48.2	California
AKG Marketing Company Limited	87.5	Bahamas
Al-Jubail Petrochemical Company (4) (5)	50	Saudi Arabia
Ampolex (CEPU) Pte Ltd	100	Singapore
Ancon Insurance Company, Inc.	100	Vermont
Barnett Gathering, LLC	100	Texas
Barzan Gas Company Limited (5)	7	Qatar
BEB Erdgas und Erdoel GmbH & Co. KG (4) (5)	50	Germany
Cameroon Oil Transportation Company S.A. (5)	41.06	Cameroon
Canada Imperial Oil Limited	69.6	Canada
Caspian Pipeline Consortium (5)	7.5	Russia/Kazakhstan
Chalmette Refining, LLC (4) (5)	50	Delaware
Cross Timbers Energy, LLC (4) (5)	50	Delaware
Cross Timbers Energy Services, Inc.	100	Texas
Ellora Energy Inc.	100	Delaware
Esso Australia Resources Pty Ltd	100	Australia
Esso Deutschland GmbH	100	Germany
Esso Erdgas Beteiligungsgesellschaft mbH	100	Germany
Esso Exploration and Production Angola (Overseas) Limited	100	Bahamas
Esso Exploration and Production Chad Inc.	100	Bahamas
Esso Exploration and Production Nigeria (Deepwater) Limited	100	Nigeria
Esso Exploration and Production Nigeria (Offshore East) Limited	100	Nigeria
Esso Exploration and Production Nigeria Limited	100	Nigeria
Esso Exploration and Production UK Limited	100	United Kingdom
Esso Exploration Angola (Block 15) Limited	100	Bahamas
Esso Exploration Angola (Block 17) Limited	100	Bahamas
Esso Italiana S.r.l.	100	Italy
Esso Nederland B.V.	100	Netherlands
Esso Norge AS	100	Norway
Esso Petroleum Company, Limited	100	United Kingdom
Esso Pipeline Investments Limited	100	Bahamas
Esso Raffinage	82.89	France
Esso Societe Anonyme Francaise	82.89	France
Esso (Thailand) Public Company Limited	65.99	Thailand
Esso Trading Company of Abu Dhabi	100	Delaware
Exxon Azerbaijan Limited	100	Bahamas
Exxon Chemical Arabia Inc.	100	Delaware
Exxon Mobile Bay Limited Partnership	100	Delaware
Exxon Neftegas Limited	100	Bahamas
Exxon Overseas Corporation	100	Delaware
Exxon Overseas Investment Corporation	100	Delaware

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
ExxonMobil Abu Dhabi Offshore Petroleum Company Limited	100	Bahamas
ExxonMobil Alaska Production Inc.	100	Delaware
ExxonMobil Asia Pacific Pte. Ltd.	100	Singapore
ExxonMobil Barzan Limited	100	Bahamas
ExxonMobil Business Finance Company	100	Nevada
ExxonMobil Canada Energy	100	Canada
ExxonMobil Canada Ltd.	100	Canada
ExxonMobil Canada Properties	100	Canada
ExxonMobil Canada Resources Company	100	Canada
ExxonMobil Capital Netherlands B.V.	100	Netherlands
ExxonMobil Central Europe Holding GmbH	100	Germany
ExxonMobil Cepu Limited	100	Bermuda
ExxonMobil Chemical France	100	France
ExxonMobil Chemical Holland B.V.	100	Netherlands
ExxonMobil Chemical Limited	100	United Kingdom
ExxonMobil China Petroleum & Petrochemical Company Limited	100	Bahamas
ExxonMobil Development Company	100	Delaware
ExxonMobil Energy Limited	100	Hong Kong
ExxonMobil Exploration and Production Malaysia Inc.	100	Delaware
ExxonMobil Exploration and Production Norway AS	100	Norway
ExxonMobil Exploration and Production Romania Limited	100	Bahamas
ExxonMobil Exploration and Production Tanzania Limited	100	Bahamas
ExxonMobil Finance Company Limited	100	United Kingdom
ExxonMobil Financial Services B.V.	100	Netherlands
ExxonMobil Gas Marketing Europe Limited	100	United Kingdom
ExxonMobil Global Services Company	100	Delaware
ExxonMobil Holding Company Holland LLC	100	Delaware
ExxonMobil Hong Kong Limited	100	Hong Kong
ExxonMobil International Finance Company	100	Delaware
ExxonMobil International Services SARL	100	Luxembourg
ExxonMobil Iraq Limited	100	Bahamas
ExxonMobil Italiana Gas S.r.l.	100	Italy
ExxonMobil Kazakhstan Inc.	100	Bahamas
ExxonMobil Kazakhstan Ventures Inc.	100	Delaware
ExxonMobil Kurdistan Region of Iraq Limited	100	Bahamas
ExxonMobil Oil Corporation	100	New York
ExxonMobil Petroleum & Chemical BVBA	100	Belgium
ExxonMobil Pipeline Company	100	Delaware
ExxonMobil PNG Limited	100	Papua New Guinea
ExxonMobil Producing Netherlands B.V.	100	Netherlands
ExxonMobil Production Deutschland GmbH	100	Germany
ExxonMobil Production Norway Inc.	100	Delaware
ExxonMobil Qatargas Inc.	100	Delaware
ExxonMobil Qatargas (II) Limited	100	Bahamas
ExxonMobil Qatargas (II) Terminal Company Limited	100	Bahamas

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
ExxonMobil Ras Laffan (III) Limited	100	Bahamas
ExxonMobil Rasgas Inc.	100	Delaware
ExxonMobil Research and Engineering Company	100	Delaware
ExxonMobil Sales and Supply LLC	100	Delaware
ExxonMobil Technology Finance Company	100	Delaware
ExxonMobil Ventures Funding Ltd.	100	Bahamas
Fujian Refining & Petrochemical Co. Ltd. (5)	25	China
Golden Pass LNG Terminal Investments LLC	100	Delaware
Golden Pass LNG Terminal LLC (5)	17.6	Delaware
Imperial Oil Limited	69.6	Canada
Imperial Oil (an Ontario General Partnership)	69.6	Canada
Imperial Oil Resources (an Alberta limited partnership)	69.6	Canada
Imperial Oil Resources N.W.T. Limited	69.6	Canada
Imperial Oil Resources Ventures Limited	69.6	Canada
Infineum Holdings B.V. (5)	50	Netherlands
Infineum USA L.P. (5)	50	Delaware
Karmorneftegaz Holding SARL (5)	33.33	Luxembourg
Mobil Australia Resources Company Pty Limited	100	Australia
Marine Well Containment Company LLC (5)	10	Delaware
McColl-Frontenac Petroleum Inc.	69.6	Canada
Mobil California Exploration & Producing Asset Company	100	Delaware
Mobil Caspian Pipeline Company	100	Delaware
Mobil Cerro Negro, Ltd.	100	Bahamas
Mobil Corporation	100	Delaware
Mobil Equatorial Guinea Inc.	100	Delaware
Mobil Erdgas-Erdoel GmbH	100	Germany
Mobil Exploration Indonesia Inc.	100	Cayman Islands
Mobil Oil Australia Pty Ltd	100	Australia
Mobil Oil Exploration & Producing Southeast Inc.	100	Delaware
Mobil Oil New Zealand Limited	100	New Zealand
Mobil Producing Nigeria Unlimited	100	Nigeria
Mobil Producing Texas & New Mexico Inc.	100	Delaware
Mobil Yanbu Petrochemical Company Inc.	100	Delaware
Mobil Yanbu Refining Company Inc.	100	Delaware
Mountain Gathering, LLC	100	Delaware
Nederlandse Aardolie Maatschappij B.V. (4) (5)	50	Netherlands
Palmetto Transoceanic LLC	100	Delaware
Papua New Guinea Liquefied Natural Gas Global Company LDC (5)	33.2	Bahamas
Phillips Exploration, LLC	100	Delaware
Qatar Liquefied Gas Company Limited (5)	10	Qatar
Qatar Liquefied Gas Company Limited (2) (5)	24.15	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (5)	24.999	Qatar

	Percentage of Voting Securities Owned Directly or Indirectly by Registrant	State or Country of Organization
Ras Laffan Liquefied Natural Gas Company Limited (II) (5)	30.517	Qatar
Ras Laffan Liquefied Natural Gas Company Limited (3) (5)	30	Qatar
Saudi Aramco Mobil Refinery Company Ltd. (4) (5)	50	Saudi Arabia
Saudi Yanbu Petrochemical Co. (4) (5)	50	Saudi Arabia
South Hook LNG Terminal Company Limited (5)	24.15	United Kingdom
Tengizchevroil, LLP (5)	25	Kazakhstan
Terminale GNL Adriatico S.r.l (5)	70.678	Italy
Trend Gathering & Treating, LLC	100	Texas
Wolverine Pipe Line Company	53.39	Delaware
XH, LLC	100	Delaware
XTO Energy Canada	84.80	Canada
XTO Energy Inc.	100	Delaware

NOTES:

(1) For the purposes of this list, if the registrant owns directly or indirectly approximately 50 percent of the voting securities of any person and approximately 50 percent of the voting securities of such person is owned directly or indirectly by another interest, or if the registrant includes its share of net income of any other unconsolidated person in consolidated net income, such person is deemed to be a subsidiary.

(2) With respect to certain companies, shares in names of nominees and qualifying shares in names of directors are included in the above percentages.

(3) The names of other subsidiaries have been omitted from the above list since considered in the aggregate, they would not constitute a significant subsidiary under Securities and Exchange Commission Regulation S-X, Rule 1-02(w).

(4) The registrant owns directly or indirectly approximately 50 percent of the securities of this person and approximately 50 percent of the voting securities of this person is owned directly or indirectly by another single interest.

(5) The investment in this unconsolidated person is represented by the registrant's percentage interest in the underlying net assets of such person. The accounting for these unconsolidated persons is referred to as the equity method of accounting.

EXHIBIT

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Form S-3 (No. 333-167787)	—	XTO Energy Inc. 2004 Stock Incentive Plan;
Form S-3 (No. 333-194609)	—	Exxon Mobil Corporation Debt Securities;
Form S-8 (Nos. 333-101175, 333-38917, 33-51107, and 333-75659)	—	1993 Incentive Program of Exxon Mobil Corporation;
Form S-8 (Nos. 333-145188, 333-110494, and 333-183012)	—	2003 Incentive Program of Exxon Mobil Corporation;
Form S-8 (Nos. 333-72955 and 333-166576)	—	ExxonMobil Savings Plan;
Form S-8 (No. 333-117980)	—	2004 Non-employee Director Restricted Stock Plan;
Form S-8 (No. 333-164620)	—	Post-effective amendment no. 1 on Form S-8 to Form S-4 relating to XTO Energy Inc. 1998 Stock Incentive Plan and 2004 Incentive Plan

of our report dated February 25, 2015, relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 25, 2015

EXHIBIT 31.

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

I, Rex W. Tillerson, certify that:

1. I have reviewed this annual report on Form 10-K of Exxon Mobil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, result operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) a 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material informat relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is be prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasona assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accoun principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure cont and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registra fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over finan reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

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

EXHIBIT 31.

Certification by Andrew P. Swiger
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Andrew P. Swiger, certify that:

1. I have reviewed this annual report on Form 10-K of Exxon Mobil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, result operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) a 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material informat relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is be prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasona assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accoun principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure cont and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registra fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over finan reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ ANDREW P. SWIGER
Andrew P. Swiger
Senior Vice President
(Principal Financial Officer)

EXHIBIT 31.

Certification by David S. Rosenthal
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, David S. Rosenthal, certify that:

1. I have reviewed this annual report on Form 10-K of Exxon Mobil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, result operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) a 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material informat relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is be prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasona assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accoun principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure cont and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registra fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over finan reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ DAVID S. ROSENTHAL

David S. Rosenthal
Vice President and Controller
(Principal Accounting Officer)

EXHIBIT 32.

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Rex W. Tillerson, the chief executive officer c Exxon Mobil Corporation (the “Company”), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the “Report”) fu complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2015

/s/ REX W. TILLERSON

Rex W. Tillerson

Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to th Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Andrew P. Swiger, the principal financial officer o Exxon Mobil Corporation (the “Company”), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the “Report”) fu complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2015

/s/ ANDREW P. SWIGER

Andrew P. Swiger
Senior Vice President
(Principal Financial Officer)

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to th Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, David S. Rosenthal, the principal accountin officer of Exxon Mobil Corporation (the "Company"), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the "Report") fu complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2015

/s/ DAVID S. ROSENTHAL

David S. Rosenthal
Vice President and Controller
(Principal Accounting Officer)

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to th Securities and Exchange Commission or its staff upon request.