

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

(State or other jurisdiction of
incorporation or organization)

13-5409005

(I.R.S. Employer
Identification Number)

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 444-1000

(Registrant's telephone number, including area code)

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

Title of Each Class

Name of Each Exchange
on Which Registered

Common Stock, without par value (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 such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirement 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 filed by Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to file 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 knowledge of the registrant, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. 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 completed second fiscal quarter, based on the closing price on that date of \$100.68 on the New York Stock Exchange composite tape, was in excess of \$429,1

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 market products in the United States and most other countries of the world. Their principal business is energy, involving exploration and production of, crude oil and natural gas, manufacture of petroleum products and transportation and sale of crude oil, natural gas and petrochemical products. ExxonMobil is a major manufacturer and marketer of commodity petrochemicals, including olefins, aromatics, polyethylene, polypropylene plastics and a wide variety of specialty products. Affiliates of ExxonMobil conduct extensive research programs in support of our businesses.

Exxon Mobil Corporation has several divisions and hundreds of affiliates, many with names that include *ExxonMobil*, *Exxon*, *Esso*, *Mobil* and *XTO*. For convenience and simplicity, in this report the terms *ExxonMobil*, *Exxon*, *Esso*, *Mobil* and *XTO*, as well as terms like *Corporate Company*, *our*, *we* and *its*, are sometimes used as abbreviated references to specific affiliates or groups of affiliates. The precise meaning can only be determined from 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 and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels, as well as pro-

monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions, and expenditures for asset retirement obligations. Using def and guidelines established by the American Petroleum Institute, ExxonMobil's 2014 worldwide environmental expenditures for a preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were \$6.2 billion, of which \$3.5 billion included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to remain in this range in 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 supplying the energy, fuel and chemical needs of both industrial and individual consumers. The Corporation competes with other firms in the purchase of needed goods and services in many national and international markets and employs all methods of competition which are lawful appropriate for such purposes.

Operating data and industry segment information for the Corporation are contained in the Financial Section of this report under the following "Quarterly Information", "Note 18: Disclosures about Segments and Related Information" and "Operating Summary". Information on oil and gas reserves is contained in the "Oil and Gas Reserves" part of the "Supplemental Information on Oil and Gas Exploration and Production Act" portion of the Financial Section of this report.

ExxonMobil has a long-standing commitment to the development of proprietary technology. We have a wide array of research programs designed to meet the needs identified in each of our business segments. Information on Company-sponsored research and development spending is contained in "Note 3: Miscellaneous Financial Information" of the Financial Section of this report. ExxonMobil held approximately 11,000 active patents worldwide at the end of 2014. For technology licensed to third parties, revenues totaled approximately \$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 on 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 active executive, management, professional, technical and wage employees who work full time or part-time for the Corporation and are covered by the Corporation's benefit plans and programs. Regular employees do not include employees of the company's unincorporated retail sites (CORS). The number of CORS employees was 8.4 thousand, 9.8 thousand, and 11.1 thousand at years 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 of profits or termination of contracts at the election of governments and risks attendant to foreign operations is found in "Item 1A—Risk Factors" and "Item 2—Properties" in this report.

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

ITEM 1A. RISK FACTORS

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

Supply and Demand

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

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

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

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

supplies. Technological change can also alter the relative costs for competitors to find, produce, and refine oil and gas and to manufacture petrochemicals.

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

Government and Political Factors

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

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

Restrictions on doing business. 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 certain of its affiliates from doing business in certain countries, or restricting the kind of business that is conducted. Such restrictions may provide a competitive advantage to competitors 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 legal frameworks for oil and gas development. Lack of legal certainty exposes our operations to increased risk of adverse or unpredictable acts by government officials, and also makes it more difficult for us to enforce our contracts. In some cases these risks can be partially offset by agreeing to arbitrate disputes in an international forum, but the adequacy of this remedy may still depend on the local legal system to enforce an award

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

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

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

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

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

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

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

Management Effectiveness

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

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

Project management. The success of ExxonMobil's Upstream, Downstream, and Chemical businesses depends on complex, long-term, intensive projects. These projects in turn require a high degree of project management expertise to maximize efficiency. Specific factors that

affect the performance of major projects include our ability to: negotiate successfully with joint venturers, partners, governments, customers, or others; model and optimize reservoir performance; develop markets for project outputs, whether through long-term contract development of effective spot markets; manage changes in operating conditions and costs, including costs of third party equipment or services such as drilling rigs and shipping; prevent, to the extent possible, and respond effectively to unforeseen technical difficulties that could delay startup or cause unscheduled project downtime; and influence the performance of project operators where ExxonMobil does not perform that

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 government payment transparency reports.

Operational efficiency. An important component of ExxonMobil’s competitive performance, especially given the commodity-based nature of our businesses, is our ability to operate efficiently, including our ability to manage expenses and improve production yields on an ongoing basis. This requires continuous management focus, including technology improvements, cost control, productivity enhancements, regular review 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 rapidly changing environment, ExxonMobil’s research and development organizations must be successful and able to adapt to a changing market and policy environment.

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information with regard to oil and gas producing activities follows:

1. Disclosure of Reserves

A. Summary of Oil and Gas Reserves at Year-End 2014

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

	Crude Oil (million bbls)	Natural Gas Liquids (million bbls)	Bitumen (million bbls)	Synthetic Oil (million bbls)	Natural Gas (billion cubic ft)	Oil-Equiv. Basis (million bbls)
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,215	287	-	-	14,169	

Canada/South America (1)	98	13	2,122	534	615
Europe	170	35	-	-	1,870
Africa	722	172	-	-	764
Asia	1,481	134	-	-	5,031
Australia/Oceania	74	38	-	-	2,179
Total Consolidated	3,760	679	2,122	534	24,628

Equity Companies

United States	259	10	-	-	194
Europe	26	-	-	-	6,484
Asia	822	366	-	-	16,305
Total Equity Company	1,107	376	-	-	22,983
Total Developed	4,867	1,055	2,122	534	47,611

Undeveloped

Consolidated Subsidiaries

United States	893	341	-	-	11,818
Canada/South America (1)	184	6	2,111	-	611
Europe	29	13	-	-	513
Africa	380	21	-	-	47
Asia	651	-	-	-	429
Australia/Oceania	67	32	-	-	5,097
Total Consolidated	2,204	413	2,111	-	18,515

Equity Companies

United States	69	6	-	-	78
Europe	1	-	-	-	1,934
Asia	278	53	-	-	1,200
Total Equity Company	348	59	-	-	3,212
Total Undeveloped	2,552	472	2,111	-	21,727

Total Proved Reserves : 7,419 1,527 4,233 534 69,338

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

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

The Corporation's overall volume capacity outlook, based on projects coming on stream as anticipated, is for production capacity to grow over the coming years. However, actual volumes will vary from year to year due to the timing of individual project start-ups, operational and reservoir performance, regulatory changes, the impact of fiscal and commercial 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 market assessments and detailed analysis of well and reservoir information such as flow rates and reservoir pressure declines. Furthermore, the Corporation only records proved reserves for projects which have received significant funding commitment and management made toward the development of the reserves. Although the Corporation is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in projections of long-term oil and gas price levels.

B. Technologies Used in Establishing Proved Reserves Additions in 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 data, utilizing well-established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The tools utilized also included subsurface information obtained through indirect 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 seismic processing software, proprietary reservoir modeling and simulation software, and commercially available data analysis packages.

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

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

ExxonMobil has a dedicated Global Reserves group that provides technical oversight and is separate from the operating organization. The responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Commission rules and regulations, review of annual changes in reserves estimates, and the reporting of ExxonMobil's proved reserves. This group also man-

the official company reserves estimates for ExxonMobil's proved reserves of crude and natural gas liquids, bitumen, synthetic oil and natural addition, the group provides training to personnel involved in the reserves estimation and reporting process within ExxonMobil and its af The Manager of the Global Reserves group has more than 30 years of experience in reservoir engineering and reserves assessment and has a in Engineering. He is an active member of the Society of Petroleum Engineers (SPE) and previously served on the SPE Oil and Gas R Committee. The group is managed by and staffed with individuals that have an average of more than 20 years of technical experience petroleum industry, including expertise in the classification and categorization of reserves under the SEC guidelines. This group i individuals who hold advanced degrees in either Engineering or Geology. Several members of the group hold professional registrations in the of expertise, and members have served on the SPE Oil and Gas Reserves Committee.

The Global Reserves group maintains a central database containing the official company reserves estimates. Appropriate controls, in limitations on database access and update capabilities, are in place to ensure data integrity within this central database. An annual review system's controls is performed by internal audit. Key components of the reserves estimation process include technical evaluations and analysis well and field performance and a rigorous peer review. No changes may be made to the reserves estimates in the central database, in additions of any new initial reserves estimates or subsequent revisions, unless these changes have been thoroughly reviewed and evaluated by authorized personnel within the operating organization. In addition, changes to reserves estimates that exceed certain thresholds require review and approval of the appropriate level of management within the operating organization before the changes may be made in the database. Endorsement by the Global Reserves group for all proved reserves changes is a mandatory component of this review process. As 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 undeveloped. This represents 35 percent of the 25.3 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 development activities in over 100 fields that resulted in the addition of approximately 0.8 GOEB from proved undeveloped to proved developed reserves by year-end. The largest transfers were related 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 development of the reserves. ExxonMobil has a disciplined investment strategy and many major fields require long lead-time in order to be developed. Development projects typically take two to four years from the time of recording proved undeveloped reserves to the time of first production. However, the development time for large and complex projects can exceed five years. During 2014, discoveries and extensions to new projects added approximately 0.6 GOEB of proved undeveloped reserves. The largest of these additions were related to planned discoveries in the United States and 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 proved 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 of 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 or more years primarily due to constraints on the capacity of infrastructure, the pace of co-venturer/government funding, as well as the time required to complete development for very large projects. The Corporation is reasonably certain that these proved reserves will be produced; however, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals, and significant changes in long-term oil and gas price levels. Of the proved undeveloped reserves that have been reported for five or more years, 84 percent are contained in the aforementioned countries. The largest of these is related to LNG/Gas projects in Australia where the construction of the Gorgon LNG project is under way. In Kazakhstan, the proved undeveloped reserves are related to the remainder of the development of the offshore Kashagan field which is included in the North Caspian Production Sharing Agreement and the Tengizchevroil joint venture which includes a production license in the Tengiz – Korolev field complex. The Tengizchevroil joint venture is producing, and the proved undeveloped reserves will continue to move to proved developed as approved development phases progress. In the Netherlands, the Groningen field has proved undeveloped reserves reported that are related to installation of future stages of compression. These reserves will move to proved developed when the additional stages of compression are installed to maintain field delivery pressure.

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

A. Oil and Gas Production

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

	2014		2013		2012	
	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Crude oil and natural gas liquids production						
Consolidated Subsidiaries						
United States	304	85	283	85	274	77
Canada/South America (1)	52	9	57	10	49	10
Europe	151	28	157	27	170	40

Africa	469	20	451	18	472
Asia	293	26	313	30	319
Australia/Oceania	39	20	29	19	32
Total Consolidated Subsidiaries	1,308	188	1,290	189	1,316
Equity Companies					
United States	63	2	61	2	61
Europe	5	-	6	-	4
Asia	236	69	373	68	345
Total Equity Companies	304	71	440	70	410
Total crude oil and natural gas liquids production	1,612	259	1,730	259	1,726
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
<i>(millions of cubic feet daily)</i>					
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
<i>(thousands of oil-equivalent barrels daily)</i>					
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 2011 and 2012 of 21 million, 28 million, and 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
During 2014						
Consolidated Subsidiaries						
Average production prices						
Crude oil, per barrel	84.00	86.46	96.43	97.46	95.27	95.56
NGL, per barrel	39.70	51.86	53.68	65.21	40.81	56.77
Natural gas, per thousand cubic feet	3.61	3.96	8.18	2.61	3.71	5.87
Bitumen, per barrel	-	62.68	-	-	-	-
Synthetic oil, per barrel	-	89.76	-	-	-	-
Average production costs, per oil-equivalent barrel - total	13.35	33.03	22.29	12.58	8.64	11.05
Average production costs, per barrel - bitumen	-	32.66	-	-	-	-
Average production costs, per barrel - synthetic oil	-	55.32	-	-	-	-
Equity Companies						
Average production prices						
Crude oil, per barrel	91.24	-	88.68	-	93.42	-
NGL, per barrel	38.77	-	-	-	65.31	-
Natural gas, per thousand cubic feet	4.54	-	8.28	-	10.00	-
Average production costs, per oil-equivalent barrel - total	24.34	-	6.10	-	1.85	-

those shown in the reserves table in the “Oil and Gas Reserves” part of the “Supplemental Information on Oil and Gas Exploration and Pro Activities” portion of the Financial Section of this report due to volumes consumed or flared. Gas is converted to an oil-equivalent basis 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
Net Productive Exploratory Wells Drilled		
Consolidated Subsidiaries		
United States	3	8
Canada/South America	3	4
Europe	1	-
Africa	2	2
Asia	-	-
Australia/Oceania	-	-
Total Consolidated Subsidiaries	<u>9</u>	<u>14</u>
Equity Companies		
United States	-	-
Europe	2	1
Asia	-	1
Total Equity Companies	<u>2</u>	<u>2</u>
Total productive exploratory wells drilled	11	16
Net Dry Exploratory Wells Drilled		
Consolidated Subsidiaries		
United States	2	2
Canada/South America	1	4
Europe	1	1
Africa	1	-
Asia	-	-
Australia/Oceania	-	-
Total Consolidated Subsidiaries	<u>5</u>	<u>7</u>
Equity Companies		
United States	2	1
Europe	-	-
Asia	-	-
Total Equity Companies	<u>2</u>	<u>1</u>
Total dry exploratory wells drilled	7	8

	2014	2013
Net Productive Development Wells Drilled		
Consolidated Subsidiaries		
United States	721	755
Canada/South America	178	201
Europe	8	13
Africa	41	33
Asia	19	30
Australia/Oceania	5	3
Total Consolidated Subsidiaries	<u>972</u>	<u>1,035</u>
Equity Companies		
United States	340	328
Europe	2	2
Asia	1	8
Total Equity Companies	<u>343</u>	<u>338</u>

Total productive development wells drilled	1,315	1,373
Net Dry Development Wells Drilled		
Consolidated Subsidiaries		
United States	6	5
Canada/South America	3	-
Europe	1	2
Africa	-	-
Asia	-	-
Australia/Oceania	-	-
Total Consolidated Subsidiaries	10	7
Equity Companies		
United States	-	-
Europe	1	1
Asia	-	-
Total Equity Companies	1	1
Total dry development wells drilled	11	8
Total number of net wells drilled	1,344	1,405

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

Synch crude Operations. Syncrude is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract crude bitumen, and then upgrade it to produce a high-quality, light (32 degrees API), sweet, synthetic crude oil. Imperial Oil Limited is the operator with a 25 percent interest in the joint venture. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited. In 2014, the company's net production of synthetic crude oil was about 60 thousand barrels per day and share of net acreage was about 63 thousand acres in the Athabasca oil sands deposit.

Kearl Project. The Kearl project is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract crude bitumen. Imperial Oil Limited holds a 70.96 percent interest in the joint venture and ExxonMobil Canada Properties holds the other 29.04 percent. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited and a 100 percent interest in ExxonMobil Canada Properties. The Kearl project 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 primarily from open-pit mining operations, and processed through a bitumen extraction and froth treatment train. The product, a blend of bitumen and diluent, is shipped to our refineries and to other third parties. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation by pipeline. During 2014, average net production at Kearl was 66 thousand barrels per day. The Kearl Expansion 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
Wells Drilling			
Consolidated Subsidiaries			
United States	1,120	442	1,199
Canada/South America	35	29	107
Europe	18	8	29
Africa	33	12	38
Asia	90	26	112
Australia/Oceania	10	4	18
Total Consolidated Subsidiaries	1,306	521	1,503
Equity Companies			
United States	31	6	9
Europe	4	1	8
Asia	1	-	11
Total Equity Companies	36	7	28
Total gross and net wells drilling	1,342	528	1,531

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 the 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 the onshore U.S., primarily in the Permian Basin of West Texas and New Mexico, the Bakken oil play in North

and Montana, and the Woodford and Caney Shales in the Ardmore and Marietta basins of Oklahoma. In addition, gas development acreage continued in the Marcellus Shale of Pennsylvania and West Virginia, the Utica Shale of Ohio, the Haynesville Shale of Texas and Louisiana, the Barnett Shale of North Texas, and the Fayetteville Shale of Arkansas.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2014 was 1.5 million acres. A total of 2.6 net exploration and development wells were completed during the year. Development activities were completed on the deepwater Hadrian South project and the non-operated Heidelberg project. ExxonMobil continued development activities on the Heidelberg and 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 wells 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 9 development wells were completed 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 development 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, development 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, started 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 continued development drilling on the deepwater Usan and Erha North Phase 2 projects. Satellite Field Development Phase 1 development drilling was completed, and the Bonga Northwest 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 was 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 Phase I oil field during the year. Field rehabilitation activities continued during 2014 and across the life of this project will include drilling new wells, working over of existing wells, and optimization and debottlenecking of existing facilities. In the Kurdistan Region of Iraq, ExxonMobil continued its seismic program and exploration drilling until operations were temporarily suspended due to security 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. Following 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 to 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 1.2 net development wells were completed. 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 wells were completed. ExxonMobil participated in 61.8 million tonnes per year gross liquefied natural gas capacity and 2.0 billion cubic feet per day of flowing gas capacity at year end. Development activities continued on the Barzan project.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 10 thousand acres onshore at year-end 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 activities 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 1.2 million acres, all offshore. ExxonMobil 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" of 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 were 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 development 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 offshore production and transportation of the gas, a 15.6 million tonnes per year LNG facility and a 280 million 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) LNG 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 LNG 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 are not included above. A total of 33.4 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 delivery of a fixed and determinable quantity for periods longer than one year. ExxonMobil also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be a combination of our own production and the spot market. Worldwide, we are contractually committed to deliver approximately 18 million barrels of oil and 2,800 billion cubic feet of natural gas for the period from 2014 through 2017. We expect to fulfill the majority of these delivery commitments with production from our proved developed reserves. Any remaining commitments will be fulfilled with production from our proved undeveloped reserves and spot market purchases as necessary.

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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
Gross and Net Productive Wells							
Consolidated Subsidiaries							
United States	24,242	9,249	36,095	21,571	23,395	8,487	38,392
Canada/South America	5,012	4,659	4,577	1,782	5,486	4,990	4,478
Europe	1,215	347	642	259	1,254	352	649
Africa	1,299	513	19	8	1,186	472	16
Asia	804	267	207	150	756	270	207
Australia/Oceania	669	157	43	21	661	147	38
Total Consolidated Subsidiaries	33,241	15,192	41,583	23,791	32,738	14,718	43,780
Equity Companies							
United States	14,571	5,605	4,365	494	14,362	5,529	4,369
Europe	57	20	567	179	49	17	555
Asia	110	27	125	30	1,329	143	122
Total Equity Companies	14,738	5,652	5,057	703	15,740	5,689	5,046
Total gross and net productive wells	47,979	20,844	46,640	24,494	48,478	20,407	48,826

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 completions 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
<i>(thousands of acres)</i>			
Gross and Net Developed Acreage			

Consolidated Subsidiaries			
United States	14,777	9,367	16,504
Canada/South America (1)	3,515	2,242	3,413
Europe	3,337	1,506	3,355
Africa	2,286	815	2,105
Asia	1,817	551	1,828
Australia/Oceania	2,123	758	2,123
Total Consolidated Subsidiaries	27,855	15,239	29,328
Equity Companies			
United States	949	208	968
Europe	4,342	1,356	4,341
Asia	628	156	5,731
Total Equity Companies	5,919	1,720	11,040
Total gross and net developed acreage	33,774	16,959	40,368

(1) Includes developed acreage in South America of 213 gross and 109 net thousands of acres for 2014 and 214 gross and 109 net thousand 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
(thousands of acres)			
Gross and Net Undeveloped Acreage			
Consolidated Subsidiaries			
United States	10,262	4,894	7,645
Canada/South America (1)	16,100	12,250	16,267
Europe	10,601	5,636	13,461
Africa	22,143	15,020	20,877
Asia	17,437	13,016	18,639
Australia/Oceania	6,653	2,013	7,144
Total Consolidated Subsidiaries	83,196	52,829	84,033
Equity Companies			
United States	350	118	363
Europe	-	-	-
Asia	191,146	63,632	34,147
Total Equity Companies	191,496	63,750	34,510
Total gross and net undeveloped acreage	274,692	116,579	118,543

(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 4,100 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 Corporation maintains exploration and/or production rights to the acreage are property-specific, contractually unique and vary significantly from property to property. Work programs are designed to ensure that the exploration potential of any property is evaluated before expiration. In some instances, the Corporation may elect to relinquish acreage in advance of the contractual expiration date if the evaluation process is complete and there is not a business basis for extension. In cases where additional time may be required to fully evaluate the acreage, the Corporation has generally been successful in obtaining extensions. The scheduled expiration of leases and concessions for undeveloped acreage over the next three years is not expected to have a material adverse impact on the Corporation.

D. Summary of Acreage Terms

UNITED STATES

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

CANADA / SOUTH AMERICA

Canada

Exploration licenses or leases in onshore areas are acquired for varying periods of time with renewals or extensions possible. These license or lease agreements entitle the holder to continue existing licenses or leases upon completing specified work. In general, these license and lease agreements are held as long as there is production on the licenses and leases. Exploration licenses in offshore eastern Canada and the Beaufort Sea are held by commitments of various amounts and rentals. They are valid for a maximum term of nine years. Production licenses in the offshore areas are valid for a maximum term of twenty years.

years, with rights of extension for continued production. Significant discovery licenses in the offshore, relating to currently undeveloped discoveries, do not have a definite term.

Argentina

The Federal 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 exploration 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 production 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. Extensions are subject to specific, minimum work commitments. Production licenses are normally granted for 20 to 25 years with multiple periods of 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 explicitly defined in the license. The term is based on the period of time necessary to perform the activities for which the license is issued. No conditions are stipulated in the license and are based on the Mining Law.

Production rights granted prior to January 1, 2003, remain subject to their existing terms, and differ slightly for onshore and offshore areas. Onshore production licenses issued prior to 1988 were indefinite; from 1988 they were issued for a period as explicitly defined in the license, ranging from 35 to 45 years. Offshore production licenses issued before 1976 were issued for a fixed period of 40 years; from 1976 they were 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-half of the original area required at the end of the sixth year and another one-fourth at the end of the ninth year. Licenses issued between 1972 and 1985 were for an initial period of up to six years (with extension of the initial period of one year at a time up to ten years after 1985), and an extension period of up to 30 years, with relinquishment of at least one-half of the original area required at the end of the initial period. Licenses issued after July 1, 1997, have an initial period of up to ten years and a normal extension period of up to 30 years or in special cases of up to 50 years, and relinquishment of at least one-half of the original area required at the end of the initial period.

United Kingdom

Acreage terms are fixed by the government and are periodically changed. For example, many of the early licenses issued under the first 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 they may 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, 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 a 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, Industries 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 period 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 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

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 can 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 option of 20 years. Operations under these pre-1969 OMLs are conducted under a joint venture agreement with NNPC rather than 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 between onshore or offshore location and are renewable, upon 12 months' written notice, for another period of 20 years. OMLs not held by NNPC are subject to a mandatory 50-percent relinquishment after the first ten years of their duration.

ASIA

Azerbaijan

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

Other exploration and production activities are governed by PSAs negotiated with the national oil company of Azerbaijan. The exploration period consists of three or four years with the possibility of a one to three-year extension. The production period, which includes development, is 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 contract (PSC), negotiated with BPMIGAS, a government agency established in 2002 to manage upstream oil and gas activities. In 2004, Indonesia's Constitutional Court ruled certain articles of law relating to BPMIGAS to be unconstitutional, but stated that all existing PSCs with BPMIGAS should remain in force until their expiry, and the functions and duties previously performed by BPMIGAS are to be carried out by the relevant Ministry of the Government of Indonesia until the promulgation of a new oil and gas law. By presidential decree, SKKMIGAS is the interim successor to BPMIGAS. The current PSCs have an exploration period of six years, which can be extended up to 10 years, an exploitation period of 20 years. PSCs generally require the contractor to relinquish 10 percent to 20 percent of the contract area after three years, and generally allow the contractor to retain no more than 50 percent to 80 percent of the original contract area after six years, depending on the terms.

Iraq

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

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

Kazakhstan

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

Offshore exploration and production activities are governed by a production sharing agreement negotiated with the Republic of Kazakhstan. The exploration period is six years followed by separate appraisal periods for each discovery. The production period for each discovery, which is for development, is for 20 years from the date of declaration of commerciality with 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 up to 29 years. All extensions are 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 first 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 economic development and production of gas reserves sufficient to satisfy the gas and LNG sales obligations of these projects.

Republic of Yemen

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

Russia

Terms for ExxonMobil's Sakhalin acreage are fixed by the production sharing agreement (PSA) that became effective in 1996 between the I government and the Sakhalin-1 consortium, of which ExxonMobil is the operator. The term of the PSA is 20 years from the Declaration of Commerciality, which would be 2021. The term may be extended thereafter in ten-year increments as specified in the PSA.

Exploration and production activities in the Kara, Laptev, Chukchi and Black Seas are governed by joint venture agreements concluded by Rosneft in 2013 and 2014 that cover 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 through 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 through 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. The 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 Company 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 prevailing at the time.

United Arab Emirates

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

AUSTRALIA/OCEANIA

Australia

Exploration and production activities conducted offshore in Commonwealth waters are governed by Federal legislation. Exploration permits are granted for an initial term of six years with two possible five-year renewal periods. Retention leases may be granted for resources that are commercially viable at the time of application, but are expected to become commercially viable within 15 years. These are granted for periods of up to five years and renewals may be requested. Prior to July 1998, production licenses were granted initially for 21 years, with a further renewal for 21 years and thereafter "indefinitely", i.e., for the life of the field. Effective from July 1998, new production licenses are granted "indefinitely". In such case, a production license may be terminated if no production operations have been carried on for five years.

Papua New Guinea

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

Information with regard to the Downstream segment follows:

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

Refining Capacity At Year-End 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
Gravencron	France		236	82.9
Karlsruhe	Germany		78	2%
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	60
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 of shutdowns for regular repair and maintenance activities, averaged over an extended period of time.
- (2) Thousands of barrels per day (KBD). ExxonMobil share reflects 100 percent of atmospheric distillation capacity in operations of Exxon and majority-owned subsidiaries. For companies owned 50 percent or less, ExxonMobil share is the greater of ExxonMobil's interest 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				<u>20,217</u>

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	ExxonM 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	60%
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, ExxonMobil's interest is ExxonMobil's interest.

ITEM 3. LEGAL PROCEEDINGS

Regarding the discussions between Chalmette Refining LLC (CRLLC), owner of the Chalmette Refinery (operated by ExxonMobil Corporation), and the Louisiana Department of Environmental Quality (LDEQ) to resolve self-reported deviations from refinery operations relating to certain Clean Air Act Title V permit conditions, limits and other requirements reported in the Corporation's Form 10-Q for the quarter of 2012, on November 14, 2014, CRLLC received a Consolidated Compliance Order and Notice of Potential Penalty (CCO/NOPP) from LDEQ covering the deviations between 2009 and 2010. CRLLC and LDEQ have entered a dispute resolution agreement, which stipulates enforcement of the 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 (EMPCo) North Line Pipeline near Torbert in Pointe Coupee Parish, Louisiana, previously reported in the Corporation's Forms 10-Q for the first quarter of 2013 and the third quarter of 2014, on December 9, 2014, LDEQ notified EMPCo that it was seeking a Penalty Assessment of \$2 million related to the discharge. EMPCo has timely requested an adjudicatory hearing on disputed issues of fact and law related to the proposed assessment.

With respect to the enforcement action filed by the United States, on behalf of the United States Environmental Protection Agency (USEPA) the State of Arkansas, on behalf of the Arkansas Department of Environmental Quality, against EMPCo related to the discharge of crude oil from the Pegasus Pipeline in Mayflower, Faulkner County, Arkansas, previously 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 court approved stay of discovery to allow parties to pursue settlement discussions.

Regarding the \$1.7 million penalty assessment against EMPCo by the U.S. Department of Transportation Pipeline & Hazardous Materials Administration (PHMSA) for alleged 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 Laurel, Montana, reported in the Corporation's Forms 10-Q for the first, second and third quarters of 2013 and the second quarter of 2014, following a 2013 administrative hearing requested by EMPCo to contest PHMSA's 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, EMPCo 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 quarters of 2014, in December 2014, XTO agreed to a settlement with the Department of Justice, USEPA and West Virginia Department of Environmental Protection (WVDEP) pursuant to which XTO would pay a 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 prepare 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 alternative locations approved by the USEPA and WVDEP. The Consent Decree is subject to final approval. On January 6, 2015, the Justice Department published a notice in the Federal Register stating that the Consent Decree had been filed 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	<i>Chairman of the Board</i>	
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 1, 2006. He still holds these positions as of this filing date.		
Mark W. Albers	<i>Senior Vice President</i>	
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	<i>Senior Vice President</i>	
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	<i>Senior Vice President</i>	
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.	<i>Senior Vice President</i>	
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 ExxonMobil Energy Inc. June 25, 2010 – May 31, 2013. 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, a position he still holds as of this filing date.		
Darren W. Woods	<i>Senior Vice President</i>	
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, 2010 – June 30, 2010. He was Vice President, Supply & Transportation, ExxonMobil Refining & Supply Company July 1, 2010 – July 31, 2012.		

President of ExxonMobil Refining & Supply Company August 1, 2012 – July 31, 2014 and Vice President of Exxon Mobil Corp August 1, 2012 – May 31, 2014. He became Senior Vice President of Exxon Mobil Corporation on June 1, 2014, a position he still holds as of this filing date.

S. Jack Balagia *Vice President and General Counsel*

Held current title since: March 1, 2010 Age: 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 Mobil Corporation on March 1, 2010, positions he still holds as of this filing date.

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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 of ExxonMobil Chemical Company April 1, 2011 – December 31, 2014. He became President of ExxonMobil Chemical Company and President of Exxon Mobil Corporation on January 1, 2015, positions he still holds as of this filing date.

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

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

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

William M. Colton *Vice President – Corporate Strategic Planning*

Held current title since: February 1, 2009 Age: 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, 2013. He was Executive Assistant to the Chairman, Exxon Mobil Corporation April 1, 2012 – February 28, 2013. He became President of Exxon Upstream Ventures and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Neil W. Duffin *President, ExxonMobil Development Company*

Held current title since: April 13, 2007 Age: 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 of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.

Stephen M. Greenlee *Vice President*

Held current title since: September 1, 2010 Age: 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 and Vice President of Exxon Mobil Corporation on September 1, 2010, positions he still holds as of this filing date.

Alan J. Kelly	<i>Vice President</i>	
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 Corporation on December 1, 2007. On February 1, 2012, the businesses of ExxonMobil Lubricants & Petroleum Specialties Company and ExxonMobil Fuels Marketing Company were consolidated and Mr. Kelly became President of the combined ExxonMobil Fuels, Lubricants & Specialties Marketing Company and Vice President of Exxon Mobil Corporation, positions he still holds as of this filing date.		
David S. Rosenthal	<i>Vice President and Controller</i>	
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. He became Vice President and Controller of Exxon Mobil Corporation on September 1, 2014, positions he still holds as of this filing date.		
Robert N. Schleckser	<i>Vice President and Treasurer</i>	
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 Mobil Corporation on May 1, 2011, positions he still holds as of this filing date.		
James M. Spellings, Jr.	<i>Vice President and General Tax Counsel</i>	
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 President and General Tax Counsel of Exxon Mobil Corporation on March 1, 2010, positions he still holds as of this filing date.		
Thomas R. Walters	<i>Vice President</i>	
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. He became President of ExxonMobil Production Company and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he still holds as of this filing date.		
Dennis G. Wascom	<i>Vice President</i>	
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 became Director, Refining North America, ExxonMobil Refining & Supply Company July 1, 2013 – July 31, 2014. He became President of Exxon Refining & Supply Company and Vice President of Exxon Mobil Corporation on August 1, 2014, positions he still holds as of this filing date.		
Jeffrey J. Woodbury	<i>Vice President – Investor Relations and Secretary</i>	
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 became Vice President, Safety, Security, Health and 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 1, 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 serving until a successor has been elected and qualified.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND 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 Yet Be Purchased Under the Plan
			Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that Yet Be Purchased Under the Plan
			Programs	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)

Note 1 - On August 1, 2000, the Corporation announced its intention to resume purchases of shares of its common stock for the treasury offset shares issued in conjunction with company benefit plans and programs and to gradually reduce the number of shares outstanding. The announcement did not specify an amount or expiration date. The Corporation has continued to purchase shares since this announcement report purchased volumes in its quarterly earnings releases. In its most recent earnings release dated February 2, 2015, the 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 through negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice.

ITEM 6. SELECTED FINANCIAL DATA

	Years Ended December 31,				2
	2014	2013	2012	2011	
(millions of dollars, except per share amounts)					
Sales and other operating revenue (1)	394,105	420,836	451,509	467,029	3
(1) Sales-based taxes included	29,342	30,589	32,409	33,503	1
Net income attributable to ExxonMobil	32,520	32,580	44,880	41,060	1
Earnings per common share	7.60	7.37	9.70	8.43	
Earnings per common share - assuming dilution	7.60	7.37	9.70	8.42	
Cash dividends per common share	2.70	2.46	2.18	1.85	
Total assets	349,493	346,808	333,795	331,052	31
Long-term debt	11,653	6,891	7,928	9,322	

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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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, Based and Other Taxes";
- "Quarterly Information" (unaudited);
- "Supplemental Information on Oil and Gas Exploration and Production Activities" (unaudited); and
- "Frequently Used Terms" (unaudited).

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

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

Management's Report on Internal Control Over Financial Reporting

Management, including the Corporation's Chief Executive Officer, Principal Financial Officer and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that ExxonMobil 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 of 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 financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Incorporated by reference to the following from the registrant's definitive proxy statement for the 2015 annual meeting of shareholders (the "Proxy Statement"):

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

ITEM 11. EXECUTIVE COMPENSATION

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

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

The information required under Item 403 of Regulation S-K is incorporated by reference to the sections "Director and Executive Office Ownership" and "Certain Beneficial Owners" of the registrant's 2015 Proxy Statement.

Equity Compensation Plan Information

Plan Category	(a)	(b)	(c)
	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted- Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excludin g Securities Reflec ted in Column (a)]
Equity compensation plans approved by security holders	24,243,615 (1)	-	109,066,057 (2)(1)
Equity compensation plans not approved by security holders	-	-	-

Total	24,243,615	-	109,066,057
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- (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 Incentive 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-employee director automatically receives 8,000 shares of restricted stock when first elected to the Board. While the director remains in office, an additional 2,500 restricted shares each following year. While on the Board, each non-employee director receives the same cash dividends on restricted shares as a holder of regular common stock, but the director is not allowed to sell the shares. The restricted shares may be forfeited if the director leaves the Board early.*

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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 “Corporate Governance” of the 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 “Ratification of Independent Auditors” of the 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.

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FINANCIAL SECTION

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BUSINESS PROFILE

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

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)	(thousands of barrels daily)	(thousands of barrels daily)
	2014	2013	2014	2013			
Net liquids production					Refinery throughput		
United States	454	431	United States			United States	1,809
Non-U.S.	1,657	1,771	Non-U.S.			Non-U.S.	2,667
Total	2,111	2,202	Total			Total	4,476
Natural gas production available for sale					Petroleum product sales		
United States	3,404	3,545	United States			United States	2,655
Non-U.S.	7,741	8,291	Non-U.S.			Non-U.S.	3,220

Total	<u>11,145</u>	<u>11,836</u>	Total	<u>5,875</u>
(thousands of oil-equivalent barrels daily)				
Oil-equivalent production (1)	3,969	4,175	Chemical prime product sales (2)	(thousands of me)
United States				
Non-U.S.			9,528	
Total			14,707	
			24,235	

(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 equity company volumes and finished-product transfers to the Downstream.

FINANCIAL SUMMARY

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

(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 \$28,547 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 covered by the Corporation's benefit plans and programs.

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

FREQUENTLY USED TERMS

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

Cash Flow From Operations and Asset Sales

Cash flow from operations and asset sales is the sum of the net cash provided by operating activities and proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments from the Consolidated Statement of Cash Flows. This cash reflects the total sources of cash from both operating the Corporation's assets and from the divesting of assets. The Corporation employs a standing and regular disciplined review process to ensure that all assets are contributing to the Corporation's strategic objectives. Assets are disposed when they are no longer meeting these objectives or are worth considerably more to others. Because of the regular nature of this activity, we believe it is useful for investors to consider proceeds associated with asset sales together with cash provided by operating activities when evaluating available for investment in the business and financing 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	44,914
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	4,035	2,707	1,107
Cash flow from operations and asset sales	<u>49,151</u>	<u>47,621</u>	<u>46,021</u>

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

Capital employed	2014	2013	2012
	(millions of dollars)		
Business uses: asset and liability perspective			
Total assets	349,493	346,808	346,808
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(47,165)	(55,916)	(55,916)
Total long-term liabilities excluding long-term debt	(92,143)	(87,698)	(87,698)
Noncontrolling interests share of assets and liabilities	(9,099)	(8,935)	(8,935)
Add ExxonMobil share of debt-financed equity company net assets	4,766	6,109	6,109
Total capital employed	<u>205,852</u>	<u>200,368</u>	<u>196,003</u>
Total corporate sources: debt and equity perspective			
Notes and loans payable	17,468	15,808	15,808
Long-term debt	11,653	6,891	6,891
ExxonMobil share of equity	174,399	174,003	174,003
Less noncontrolling interests share of total debt	(2,434)	(2,443)	(2,443)
Add ExxonMobil share of equity company debt	4,766	6,109	6,109
Total capital employed	<u>205,852</u>	<u>200,368</u>	<u>196,003</u>

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 calculated as business segment earnings divided by average business segment capital employed (average of beginning and end-of-year amounts). These segment earnings include ExxonMobil's share of segment earnings of equity companies, consistent with our capital employed definition, and excludes the cost of financing. The Corporation's total ROCE is net income attributable to ExxonMobil excluding the after-tax cost of financing, divided by corporate average capital employed. The Corporation has consistently applied its ROCE definition for many years and views it as the best measure of historical capital productivity in our capital-intensive, long-term industry, both to evaluate management's performance and to demonstrate the value of our capital.

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

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

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

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

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

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

FORWARD-LOOKING STATEMENTS

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

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

OVERVIEW

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

ExxonMobil, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new energy supplies. While commodity prices are volatile on a short-term basis and dependent upon supply and demand, ExxonMobil's investment decisions are based on our long-term business outlook, using a disciplined approach in select areas to pursue the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Price ranges for crude oil, natural gas, refined products and chemical products are based on corporate plan assumptions developed annually by major region and are utilized for investment evaluation purposes. Potential investment opportunities are evaluated over a wide range of economic scenarios to establish the resiliency of each opportunity.

Once investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into 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 population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. As economies and populations grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with significant efficiency gains energy demand is projected to rise by about 35 percent from 2010 to 2040. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organisation for Economic Co-operation and Development).

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

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 40 percent from 2010 to 2040. The growth in transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide during this period. Nearly all the world's transportation fleets will continue to run 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 generation is expected to remain the largest and fastest-growing major segment of global energy demand. Meeting the expected growth in power demand will require a diverse set of energy sources. Natural gas demand is likely to grow most significantly and become the leading source of generated electricity by 2040, reflecting the efficiency of gas-fired power plants. Today, coal has the largest share in the power sector, but its share is likely to decline significantly by 2040 as policies are gradually adopted to reduce environmental impact, including those related to local air quality and greenhouse gas emissions. Nuclear power and renewables, led by hydropower and wind, are expected to grow significantly over the period.

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

Liquid fuels provide the largest share of global energy supplies today due to their broad-based availability, affordability and ease of transportation, distribution and storage to meet consumer needs. By 2040, global demand for liquid fuels is expected to grow to approximately 115 million barrels of oil-equivalent per day, an increase of almost 30 percent from 2010. Globally, crude production from traditional conventional sources will likely decrease slightly through 2040, with significant development activity mostly offsetting natural declines from 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, natural gas liquids and biofuels. The world's resource base is sufficient to meet projected demand through 2040 as technological advances continue to expand the availability of economic supply options. However, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel, suitable for a wide variety of applications, and is expected to be the fastest growing major fuel source through 2040. Global demand is expected to rise about 65 percent from 2010 to 2040, with about half of that increase in the Asia Pacific region. In addition to meet these needs will be significant growth in supplies of unconventional gas – the natural gas found in shale and other rock formations that were once considered uneconomic to produce. About two-thirds of the growth in natural gas supplies is expected to be from 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 triple by 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 2040. 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 exceed 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 rising electricity needs as well as security and environmental issues. Total renewable energy is likely to reach about 15 percent of total energy by 2040, with biomass, hydro, wind and geothermal contributing a combined share of more than 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase from close to 450 percent from 2010 to 2040, 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 increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these resources will be significant. According to the International Energy Agency, the investment required to meet total oil and gas energy needs worldwide over the 2014-2040 period 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 predict their business impact. ExxonMobil includes estimates of potential costs related to possible public policies covering energy-related greenhouse gas emissions in its long-term *Outlook for Energy*, which is used 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 analyses as well as publicly available information from external sources including the International Energy Agency.

Upstream

ExxonMobil continues to maintain a diverse portfolio of exploration and development opportunities, which enables the Corporation to be se maximizing shareholder value and mitigating political and technical risks. ExxonMobil's fundamental Upstream business strategies gu global exploration, development, production, and gas and power marketing activities. These strategies include capturing material and ac opportunities to continually high-grade the resource portfolio, exercising a disciplined approach to investing and cost management, develop applying high-impact technologies, pursuing productivity and efficiency gains, growing profitable oil and gas production, and capitaliz growing natural gas and power markets. These strategies are underpinned by a relentless focus on operational excellence, commitment to inn technologies, development of our employees, and investment in the communities within which we operate.

As future development projects and drilling activities bring new production online, the Corporation expects a shift in the geographic mix the type of opportunities from which volumes are produced. Oil equivalent production from North America is expected to increase over t several years based on current capital activity plans, contributing over a third of total production. Further, the proportion of our global pro from resource types utilizing specialized technologies such as arctic, deepwater, and unconventional drilling and production systems, 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 chang geographic mix of production volumes, and in the types of opportunities from which volumes will be produced, will have a material impact c

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

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 gr the next few years. However, actual volumes will vary from year to year due to the timing of individual project start-ups and other capital ac operational outages, reservoir performance, performance of enhanced oil recovery projects, regulatory changes, the impact of fiscal and com terms, asset sales, weather events, price effects on production sharing contracts and other factors described in Item 1A. Risk Factors. Enh recovery projects extract hydrocarbons from reservoirs in excess of that which may be produced through primary recovery, i.e., through p depletion or natural aquifer support. They include the injection of water, gases or chemicals into a reservoir to produce hydrocarbons ot unobtainable.

The markets for crude oil and natural gas have a history of significant price volatility. After some years of relatively stable prices, the 2014 saw crude prices drop to levels not seen since 2009. ExxonMobil believes prices over the long term will continue to be driven by supply and demand, with the demand side largely being a function of global economic growth. To manage the risks associated with ExxonMobil evaluates annual plans and all investments across a wide range of price scenarios. The Corporation's assessment is that its ope will continue to be successful in a variety of market conditions. This is the outcome of disciplined investment, cost management, an enhancement programs.

Downstream

ExxonMobil's Downstream is a large, diversified business with refining, logistics, and marketing complexes around the world. The Corporat a presence in mature markets in North America and Europe, as well as in the growing Asia Pacific region. ExxonMobil's fundamental Dow business strategies position the company to deliver long-term growth in shareholder value that is superior to competition across a range of conditions. These strategies include targeting best-in-class operations in all aspects of the business, maximizing value from advanced techn capitalizing on integration across ExxonMobil businesses, selectively investing for resilient, advantaged returns, operating efficiently effectively, 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 c lubricant basestock manufacturing capacity of 131 thousand barrels per day. ExxonMobil's fuels and lubes marketing businesses have sig global reach, with multiple channels to market serving a diverse customer base. Our portfolio of world-renowned brands includes *Exxon*, *Esso* and *Mobil* 1.

The downstream industry environment remains challenging. Demand weakness and overcapacity in the refining sector will continue to i competitive pressure. In the near term, we see variability in refining margins, with some regions seeing weaker margins as new capacity ac outpace global demand. In North America, lower raw material and energy cost driven by increasing crude oil and natural gas product 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 pay: raw materials (primarily crude oil) and the market prices for the range of products produced (primarily gasoline, heating oil, diesel oil, jet f fuel oil). Crude oil and many products are widely traded with published prices, including those quoted on multiple exchanges around the (e.g., New York Mercantile Exchange and Intercontinental Exchange). Prices for these commodities are determined by the global marketpli are influenced by many factors, including global and regional supply/demand balances, inventory levels, industry refinery operations, import balances, 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 c additions outpace the growth in global demand. Additionally, as described in more detail in Item 1A. Risk Factors, proposed carbon policy ar climate-related regulations in many countries, as well as the continued growth in biofuels mandates, could have negative impacts on the i business. ExxonMobil's integration across the value chain, from refining to marketing, enhances overall value in both fuels and lul businesses.

In the retail fuels marketing business, competition has caused inflation-adjusted margins to decline. In 2014, ExxonMobil expanded its t retail site network in the U.S. and progressed the multi-year transition of the direct served (i.e., dealer, company-operated) retail network in p of Europe to a more capital-efficient branded distributor model. ExxonMobil is increasing investment in its fuels brands and developing n programs that will enhance the value of its consumer retail offer. The company's lubricants business continues to grow, leveraging wor

brands and integration with industry-leading basestock refining capability. ExxonMobil remains a market leader in the high-value sy 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 ma the past decade. When investing in the Downstream, ExxonMobil remains focused on selective and resilient

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

projects. These investments capitalize on the Corporation's world-class scale and integration, demonstrated efficiency, advanced technolo respected brands, enabling ExxonMobil to take advantage of attractive emerging growth opportunities around the globe. In 2014, the co commissioned the clean fuels project at the joint Saudi Aramco and ExxonMobil SAMREF Refinery in Yanbu, Saudi Arabia, to produce low gasoline and ultra-low sulfur diesel. Construction started on a new delayed coker unit at the refinery in Antwerp, Belgium, to upgrade low bunker fuel into high-value diesel products. The company also completed an expansion of lube basestock capacity at the refinery in Singapore. Nearred completion on a lube basestock expansion in Baytown, Texas. A finished lubricant plant expansion in Tianjin, China, was comple additional lubricant plant expansions in China, Singapore, Finland, and the U.S. are underway to support demand growth for finished lubrica greases in key markets.

Chemical

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

ExxonMobil sustained its competitive advantage through continued operational excellence, investment and cost discipline, a balanced p of products, integration with refining 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 crack polyethylene lines, to capitalize on low-cost feedstock and energy supplies in North America and meet rapidly growing demand for plastic polymers. Construction of new halobutyl rubber and hydrocarbon resin units also started in Singapore to further extend our specialty j capacity in Asia. At the joint venture facility in Al-Jubail, Saudi Arabia, construction continued on the specialty elastomers project that is e to start-up in 2015.

REVIEW OF 2014 AND 2013 RESULTS

	2014	2013	(millions of dollars)
Earnings (U.S. GAAP)			
Net income attributable to ExxonMobil (U.S. GAAP)	32,520	32,580	
Upstream			
	2014	2013	
Upstream			
United States	5,197	4,191	
Non-U.S.	22,351	22,650	
Total	<u>27,548</u>	<u>26,841</u>	

2014

Upstream earnings were \$27,548 million, up \$707 million from 2013. Lower prices decreased earnings by \$2.0 billion. Favorable volume increased earnings by \$510 million. All 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 was 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 barrels 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 the impact, liquids 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 2013, 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, up \$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 million. Production volume and mix effects decreased earnings by \$910 million. All other items, including lower gains from asset sales, mainly in Angola, and higher expenses, reduced earnings by \$2.5 billion. On an oil-equivalent basis, production was down 1.5 percent compared to 2012. Excluding the impacts of entitlement

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

volumes, OPEC quota effects and divestments, production was essentially flat. Liquids production of 2.2 million barrels per day in 17,000 barrels per day compared with 2012. Excluding the impacts of entitlement volumes, OPEC quota effects and divestments, liquids production was up 1.6 percent, as project ramp-up and lower downtime were partially offset by field decline. Natural gas production of 11.8 billion cubic feet per day decreased 486 million cubic feet per day from 2012. Excluding the impacts of entitlement volumes and divestments, natural gas production was down 1.5 percent, as field decline was partially offset by higher demand, lower downtime, and project ramp-up. Earnings from U.S. Upstream operations for 2013 were \$4,191 million, up \$266 million from 2012. Earnings outside the U.S. were \$22,650 million, down \$3,320 million from the prior year.

Upstream Additional Information

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

(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 net interest changes specified in Production Sharing Contracts (PSCs) which typically occur when current investment returns or production volumes achieve defined thresholds, changes in equity upon achieving pay-out in partner investment situations, equity redeterminations as specified in venture agreements, or as a result of the termination or expiry of a concession. Once a net 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 in operational volume-determining factors. 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, price or spending variability can increase or decrease burdens and/or volumes attributable to ExxonMobil. For example, at higher prices, fewer barrels are required for ExxonMobil to 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 include other temporary 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 Petroleum 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 an asset in exchange for financial or other 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. Such factors include, but are not limited to, production enhancements from project and work program activities, acquisitions including additions from asset exchanges, downtime, market demand, natural field decline, and any fiscal or commercial terms that do not affect entitlements.

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

Downstream

	2014	2013
	(millions of dollars)	
Downstream		
United States	1,618	2,199
Non-U.S.	1,427	1,250
Total	<u>3,045</u>	<u>3,449</u>

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 by \$480 million. All other items, primarily unfavorable foreign exchange and tax impacts, partially offset by expenses, decreased earnings by \$650 million. Petroleum product sales of 5.9 million barrels per day were in line with 2013. U.S. Dowtow earnings were \$1,618 million, a decrease of \$581 million from 2013. Non-U.S. Downstream earnings were \$1,427 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 Japan restructuring. Lower margins, mainly refining, decreased earnings by \$2.9 billion. Volume and mix effects decreased earnings by \$310 million. All other items, including higher operating expenses, unfavorable foreign exchange impacts, and lower divestments, decreased earnings by \$1.2 billion. Petroleum product sales of 5.9 million barrels per day decreased 287,000 barrels per day from 2012. U.S. Dowtow 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.

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

Chemical

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

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 increased 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 tons from 2013, driven by increased Singapore production. Chemical earnings were \$2,804 million, up \$49 million from 2013. Non-U.S. Chemical earnings were \$1,511 million, \$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. Higher 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 from 2012. U.S. Chemical earnings were \$2,755 million, up \$535 million from 2012. Non-U.S. Chemical earnings were \$1,073 million, \$605 million lower than the prior year.

Corporate and Financing

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

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.

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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	44,914
Investing activities	(26,975)	(34,201)	(34,201)
Financing activities	(17,888)	(15,476)	(15,476)
Effect of exchange rate changes	(281)	(175)	(175)
Increase/(decrease) in cash and cash equivalents	<u>(28)</u>	<u>(4,938)</u>	<u>(4,938)</u>
			(December 31)
Cash and cash equivalents	4,616	4,644	4,644
Cash and cash equivalents - restricted	42	269	269
Total cash and cash equivalents	<u>4,658</u>	<u>4,913</u>	<u>4,913</u>

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 noncontrolling 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 \$3.3 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, dividends to shareholders of \$10.9 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 of 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 including noncontrolling interests of \$33.4 billion, the adjustment for the noncash provision of \$17.2 billion for depreciation and depletion, and a net debt increase of \$11.6 billion. The major uses of funds included spending for additions to property, plant and equipment of \$33.7 billion, the purchase of ExxonMobil stock of \$16.0 billion, dividends to shareholders of \$10.9 billion and a change in working capital, excluding cash and debt, of \$4.7 billion. Included in total cash and cash equivalents at year-end 2013 was \$0.3 billion of restricted cash. For additional details, see the Consolidated Statement of Cash Flows.

The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, 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-term lines of credit of \$0.5 billion. Cash that may be temporarily available in surplus to the Corporation's immediate needs is carefully managed through counterparty quality and investment guidelines to ensure it is 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 implement new technologies and recovery processes to existing fields, in order to maintain or increase production. After a period of production at plateau it is the nature of oil and gas fields eventually to produce at declining rates for the remainder of their economic life. Averaged over the Corporation's existing oil and gas fields and without new projects, ExxonMobil's production is expected to decline at an average of approximately 5 percent per year over the next few years. Decline rates can vary widely by individual field due to a number of factors, including, but not limited to, the type of reservoir, fluid properties, recovery mechanisms, work activity, and age of the field. Furthermore, the Corporation's net interest in production for individual fields can vary with price and 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 last decade, this has resulted in net annual additions to proved reserves that have exceeded the amount produced. Projects are in progress or planned to increase production capacity. However, these volume increases are subject to a variety of risks including project start-up timing, operational outages, reservoir performance, the impact of fiscal and commercial terms, crude oil and natural gas prices, weather events, and regulatory changes. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please see Item 1A. Risk Factors for a more complete discussion of risks.

The Corporation's financial strength enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2014 were \$38.5 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an average investment profile of approximately \$34 billion per year for the next few years. Actual spending could vary depending on the progress of individual projects and property acquisitions. The Corporation has a large and diverse portfolio of

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

development projects and exploration opportunities, which helps mitigate the overall political and technical risks of the Corporation's Upstream segment and associated cash flow. Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the Corporation's liquidity or ability to generate sufficient cash for operations and its fixed commitments. The purchase and sale of oil and gas properties have not had a significant impact on the amount or 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 including noncontrolling interests of \$33.6 billion, an increase of \$0.2 billion. The noncash provision for depreciation and depletion was billion, up \$0.1 billion from the prior year. The adjustment for net gains on asset sales 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 including noncontrolling interests of \$33.4 billion, a decrease of \$14.2 billion. The noncash provision of \$17.2 billion for depreciation and depletion was higher than 2012. The adjustment for net gains on asset sales was \$1.8 billion compared to an adjustment of \$13.0 billion in 2012. Changes in operational working capital, excluding cash and debt, decreased cash in 2013 by \$4.7 billion.

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 decreased \$0.7 billion from 2013. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and retirements of \$4.0 billion compared to \$2.7 billion in 2013. Additional investments and advances were \$2.8 billion lower in 2014, while cash 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 decreased \$33.7 billion decreased \$0.6 billion from 2012. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and retirements of \$2.7 billion compared to \$7.7 billion in 2012. Additional 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 per share from \$2.46 per share and totaled \$11.6 billion, a pay-out of 36 percent of net income. During the first quarter of 2014, the Corp issued \$5.5 billion of long-term debt. Total debt increased \$6.4 billion to \$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 ExxonMobil shareholders of \$23.6 billion, composed of \$11.6 billion in dividends and \$12.0 billion of purchases of ExxonMobil stock to reduce shares outstanding. Foreign exchange translation 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. Purchases were made to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 3.1 percent from 4,335 million to 4,201 million at the end of 2014. Purchases were made in both the market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

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

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 per share from \$2.18 per share and totaled \$10.9 billion, a pay-out of 33 percent of net income. Total debt increased \$11.1 billion to \$22.7 billion at year-end.

ExxonMobil share of equity increased \$8.1 billion to \$174.0 billion. The addition to equity for earnings of \$32.6 billion was partially offset by reductions for distributions to ExxonMobil shareholders of \$10.9 billion of dividends and \$15.0 billion of purchases of shares of ExxonMobil 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. Purchases were made to reduce the number of shares outstanding and to offset shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 3.7 percent from 4,502 million to 4,335 million at the end of 2013. Purchases were made in both the 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. The table combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

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

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

Notes:

- (1) Includes capitalized lease obligations of \$375 million.
- (2) The amount due in one year is included in notes and loans payable of \$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 postretirement plans at year end. The payments by period include expected contributions to funded pension plans in 2015 and estimated 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 properties.
- (6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable or cancelable only under specific conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. Undiscounted obligations of \$1,095 million mainly pertain to pipeline throughput agreements and include \$433 million of obligations to 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 pertain to 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 primarily associated with Upstream 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 expects 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 and performance under contracts (Note 16). Where guarantees for environmental remediation and other similar matters do not include a statement of maximum potential exposure, the amounts reflect management's estimate of the maximum potential exposure. These guarantees are not reasonably likely to have a material effect on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Financial Strength

On December 31, 2014, the Corporation's unused short-term committed lines of credit totaled approximately \$6.3 billion (Note 6) and unused term committed lines of credit totaled 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's creditworthiness.

	2014	2013
Fixed-charge coverage ratio (times)	46.9	55.7
Debt to capital (percent)	13.9	11.2
Net debt to capital (percent)	11.9	9.1

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

Litigation and Other Contingencies

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

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

CAPITAL AND EXPLORATION EXPENDITURES

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

(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 XTO Energy Ltd. acquisition in 2013. The 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 and 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 acquisitions in 2013. Investments in 2014 included projects in the U.S. Gulf of Mexico, U.S. onshore drilling, exploration in Russia and continued growth in world-class projects in Canada and Australia. The majority of expenditures are on development projects, which typically take two to four years from the time of recording proved undeveloped reserves to the start of production. The percentage of proved developed reserves was 65 percent of proved reserves at year-end 2014, and has been over 60 percent for the last ten years, indicating that proved reserves are consistently moving from 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 infrastructure. The Chemical capital expenditures of \$2.7 billion increased \$0.9 billion from 2013 with higher investment in the U.S.

TAXES

	2014	2013
<i>(millions of dollars)</i>		
Income taxes	18,015	24,263
<i>Effective income tax rate</i>	41%	48%
Sales-based taxes	29,342	30,589
All other taxes and duties	35,515	36,396
Total	82,872	91,248

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, was \$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 impacts 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. Inc expense, both current and deferred, was \$24.3 billion, \$6.8 billion lower than 2012, with the impact of lower earnings partially offset by the effective tax rate. The effective tax rate was 48 percent compared to 44 percent in the prior year due to the absence of favorable tax imp divestments. Sales-based and all other taxes and duties of \$67.0 billion in 2013 decreased \$4.3 billion reflecting the 2012 Japan restructuring.

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ENVIRONMENTAL MATTERS

Environmental Expenditures

	2014
	<i>(millions of dollars)</i>
Capital expenditures	2,666
Other expenditures	3,522
Total	6,188

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels, as well as projects to reduce sulfur oxide and greenhouse gas emissions, and expenditures for asset retirement obligations. Using definitive guidelines established by the American Petroleum Institute, ExxonMobil's 2014 worldwide environmental expenditures for all such prevention and remediation steps, including ExxonMobil's share of equity company expenditures, were about \$6.2 billion. 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).

Environmental Liabilities

The Corporation accrues environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for potential environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency has identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at these multiparty sites may mitigate ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil's operations or financial condition. Consolidated company provisions made in 2014 for environmental liabilities were \$780 million (\$321 million in 2013) and the balance sheet reflects accumulated 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
Crude oil and NGL (\$/barrel)	87.42	97.48
Natural gas (\$/kcf)	4.68	4.60

(1) *Consolidated subsidiaries.*

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

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

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

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

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

Risk Management

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

The Corporation is exposed to changes in interest rates, primarily on its short-term debt and the portion of long-term debt that carries floating interest rates. The impact of a 100-basis-point change in interest rates affecting the Corporation's debt would not be material to earnings, cash flows or fair value. The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are expected to cover the majority of financial requirements, supplemented by long-term and short-term debt. Some joint-venture partners are dependent on 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, exports, financing and investment transactions. The impacts of fluctuations in exchange rates on ExxonMobil's geographically and functionally diverse operations are varied and often offsetting in amount. The Corporation makes limited use of currency exchange contracts to mitigate the impact of changes in currency values, and exposures related to the Corporation's limited use of the currency exchange contracts are not material.

Inflation and Other Uncertainties

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

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

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 for all contracts with customers, eliminates industry specific requirements, and expands disclosure requirements. The standard is required to be adopted beginning January 1, 2017. 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 hydrocarbon-based products. The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The Corporation's accounting policies are summarized in Note 1.

Oil and Gas Reserves

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

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

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

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

Proved reserves can be further subdivided into developed and undeveloped reserves. The percentage of proved developed reserves has been over 60 percent of total proved reserves at year-end 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 from undeveloped to developed status.

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

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

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

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

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that are individually significant are aggregated by groups and amortized based on development risk and average holding period.

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses assist the Corporation in assessing whether the carrying amounts of any of its assets may not be recoverable. In addition to estimating oil and gas volumes in conducting these analyses, it is also necessary to estimate future oil and gas prices. Potential trigger events for impairment evaluation include a significant decrease in current and projected reserve volumes, an accumulation of project costs significantly in excess of the 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 reason is that crude oil and natural gas have a history of significant price volatility. Although prices will occasionally drop significantly, industry prices in the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world supplies. The demand side is largely a function of global economic growth. The relative growth/decline in supply versus demand will determine industry prices over the long term, and these cannot be accurately predicted.

Accordingly, any impairment tests that the Corporation performs make use of the Corporation's price assumptions developed in the planning and budgeting process for the crude oil and natural gas markets, petroleum products and chemicals. These are the same price assumptions that are used for capital investment decisions. Volumes are based on field production profiles, which are updated annually. Cash flow estimates used 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 the consolidated financial statements. Future prices used for any impairment tests will vary from the ones used in the supplemental oil and gas disclosure and could be lower or higher for any given year.

Asset Retirement Obligations

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

Suspended Exploratory Well Costs

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

Consolidations

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

Investments in companies that are partially owned by the Corporation are integral to the Corporation's operations. In some cases they are used to balance worldwide risks, and in others they provide the only available means of entry into a particular market or area of interest. The other shareholders who also have an equity interest in these companies are either independent third parties or host governments that share in the business according to their ownership. The Corporation does not invest in these companies in order to remove liabilities from its balance sheet. In fact, the Corporation has long been on record supporting an

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

alternative accounting method that would require each investor to consolidate its share of all assets and liabilities in these partially-owned companies rather than only its interest in net equity. This method of accounting for investments in partially-owned companies is not permitted under U.S. GAAP except where the investments are in the direct ownership of a share of upstream assets and liabilities. However, for purposes of calculating return on average capital employed, which is not covered by U.S. GAAP standards, the Corporation includes its share of debt of 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) provides details on pension obligations, fund assets and pension expense.

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

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

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

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations and the long-term rate for future salary increases. Pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long-term expected rate of return on U.S. pension plan assets in 2014 was 7.25 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 7 percent and 6.5 percent, respectively. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term assumption for each pension fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term expected assumption for each asset class. A worldwide reduction of 0.5 percent in the long-term rate of return on assets would increase annual pension expense by approximately \$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 in which a difference occurs. Such differences are deferred, along with other actuarial gains and losses, and are amortized into pension expense over the expected remaining service life of employees.

Litigation Contingencies

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

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

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

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

adverse effect on operations or financial condition. In the Corporation's experience, large claims often do not result in large awards. Large claims are often reversed or substantially reduced as a result of appeal or settlement.

Tax Contingencies

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

The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely to be realized. A reserve is established for the difference between a position taken or expected to be taken in an income tax return and the benefit recognized in the financial statements. The Corporation's unrecognized tax benefits and a description of open tax years are summarized in Note 16.

Foreign Currency Translation

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

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

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation's Chief Executive Officer, Principal Financial Officer, and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that ExxonMobil 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 of 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)

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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 I Changes in Equity and Cash Flows present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidi December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended Decem 2014 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Corporation mai in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Corpo management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assess the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Fi Reporting. Our responsibility is to express opinions on these financial statements and on the Corporation's internal control over financial re based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial stat are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Ou of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial stat assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement prese Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assess risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assess Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits pr 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 fi reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting prin company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assuar transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting pri and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition 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 evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 25, 2015

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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	421,200
Income from equity affiliates	7	13,323	13,927	13,927
Other income		4,511	3,492	2,409
Total revenues and other income		411,939	438,255	421,200
Costs and other deductions				
Crude oil and product purchases		225,972	244,156	241,200
Production and manufacturing expenses		40,859	40,525	40,525
Selling, general and administrative expenses		12,598	12,877	12,877
Depreciation and depletion		17,297	17,182	17,182
Exploration expenses, including dry holes		1,669	1,976	1,976
Interest expense		286	9	9
Sales-based taxes (1)	19	29,342	30,589	30,589
Other taxes and duties	19	32,286	33,230	32,409
Total costs and other deductions		360,309	380,544	380,544
Income before income taxes		51,630	57,711	57,711
Income taxes	19	18,015	24,263	24,263
Net income including noncontrolling interests		33,615	33,448	33,448
Net income attributable to noncontrolling interests		1,095	868	868
Net income attributable to ExxonMobil		32,520	32,580	32,580
Earnings per common share (<i>dollars</i>)	12	7.60	7.37	7.37
Earnings per common share - assuming dilution (<i>dollars</i>)	12	7.60	7.37	7.37

(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.

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CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2014	2013	2012
	(millions of dollars)		
Net income including noncontrolling interests	33,615	33,448	-
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(5,847)	(3,620)	-
Adjustment for foreign exchange translation (gain)/loss included in net income	152	(23)	-
Postretirement benefits reserves adjustment (excluding amortization)	(4,262)	3,174	-
Amortization and settlement of postretirement benefits reserves			
adjustment included in net periodic benefit costs	1,111	1,820	-
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	-
Comprehensive income including noncontrolling interests	24,709	34,799	-
Comprehensive income attributable to noncontrolling interests	421	760	-
Comprehensive income attributable to ExxonMobil	24,288	34,039	-

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

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CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2014	Dec. 2014	Dec. 2013
		(millions of dollars)		
Assets				
Current assets				
Cash and cash equivalents		4,616		
Cash and cash equivalents - restricted		42		
Notes and accounts receivable, less estimated doubtful amounts	6	28,009		
Inventories				
Crude oil, products and merchandise	3	12,384		
Materials and supplies		4,294		
Other current assets		3,565		
Total current assets		<u>52,910</u>		
Investments, advances and long-term receivables	8	35,239		
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	252,668	2	
Other assets, including intangibles, net		8,676		
Total assets		<u>349,493</u>	3	
Liabilities				
Current liabilities				
Notes and loans payable	6	17,468		
Accounts payable and accrued liabilities	6	42,227		
Income taxes payable		4,938		
Total current liabilities		<u>64,633</u>		
Long-term debt	14	11,653		
Postretirement benefits reserves	17	25,802		
Deferred income tax liabilities	19	39,230		
Long-term obligations to equity companies		5,325		
Other long-term obligations		21,786		
Total liabilities		<u>168,429</u>	1	
Commitments and contingencies		16		
Equity				
Common stock without par value				
(9,000 million shares authorized, 8,019 million shares issued)		10,792		
Earnings reinvested		408,384	3	
Accumulated other comprehensive income		(18,957)	(
Common stock held in treasury				
(3,818 million shares in 2014 and 3,684 million shares in 2013)		(225,820)	(2	
ExxonMobil share of equity		174,399	1	
Noncontrolling interests		6,665		
Total equity		<u>181,064</u>	1	
Total liabilities and equity		<u>349,493</u>	3	

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	
Adjustments for noncash transactions				
Depreciation and depletion		17,297	17,182	

Deferred income tax charges/(credits)		1,540	754
Postretirement benefits expense			
in excess of/(less than) net payments		524	2,291
Other long-term obligation provisions			
in excess of/(less than) payments		1,404	(2,566)
Dividends received greater than/(less than) equity in current			
earnings of equity companies		(358)	3
Changes in operational working capital, excluding cash and debt			
Reduction/(increase) - Notes and accounts receivable		3,118	(305)
- Inventories		(1,343)	(1,812)
- Other current assets		(68)	(105)
Increase/(reduction) - Accounts and other payables		(6,639)	(2,498)
Net (gain) on asset sales	5	(3,151)	(1,828)
All other items - net		(823)	350
Net cash provided by operating activities		45,116	44,914
Cash flows from investing activities			
Additions to property, plant and equipment		(32,952)	(33,669)
Proceeds associated with sales of subsidiaries, property, plant			
and equipment, and sales and returns of investments	5	4,035	2,707
Decrease/(increase) in restricted cash and cash equivalents		227	72
Additional investments and advances		(1,631)	(4,435)
Collection of advances		3,346	1,124
Net cash used in investing activities		(26,975)	(34,201)
Cash flows from financing activities			
Additions to long-term debt		5,731	345
Reductions in long-term debt		(69)	(13)
Additions to short-term debt		-	16
Reductions in short-term debt		(745)	(756)
Additions/(reductions) in debt with three months or less maturity		2,049	12,012
Cash dividends to ExxonMobil shareholders		(11,568)	(10,875)
Cash dividends to noncontrolling interests		(248)	(304)
Changes in noncontrolling interests		-	(1)
Tax benefits related to stock-based awards		115	48
Common stock acquired		(13,183)	(15,998)
Common stock sold		30	50
Net cash used in financing activities		(17,888)	(15,476)
Effects of exchange rate changes on cash		(281)	(175)
Increase/(decrease) in cash and cash equivalents		(28)	(4,938)
Cash and cash equivalents at beginning of year		4,644	9,582
Cash and cash equivalents at end of year		4,616	4,644

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						F	
	Common Stock	Earnings Reinvested	Accumulated Other	Common Stock	ExxonMobil Share of Equity	Non-controlling Interests		
			Comprehensive Income	Held in Treasury				
(millions of dollars)								
Balance as of December 31, 2011	9,512	330,939	(9,123)	(176,932)	154,396	6,348		
Amortization of stock-based awards	806	-	-	-	806	-		
Tax benefits related to stock-based awards	178	-	-	-	178	-		
Other	(843)	-	-	-	(843)	(1,441)		
Net income for the year	-	44,880	-	-	44,880	2,801		
Dividends - common shares	-	(10,092)	-	-	(10,092)	(327)		
Other comprehensive income	-	-	(3,061)	-	(3,061)	(1,550)		
Acquisitions, at cost	-	-	-	(21,068)	(21,068)	(34)		
Dispositions	-	-	-	667	667	-		

Balance as of December 31, 2012	9,653	365,727	(12,184)	(197,333)	165,863	5,797
Amortization of stock-based awards	761	-	-	-	761	-
Tax benefits related to stock-based awards	162	-	-	-	162	-
Other	(499)	-	-	-	(499)	240
Net income for the year	-	32,580	-	-	32,580	868
Dividends - common shares	-	(10,875)	-	-	(10,875)	(304)
Other comprehensive income	-	-	1,459	-	1,459	(108)
Acquisitions, at cost	-	-	-	(15,998)	(15,998)	(1)
Dispositions	-	-	-	550	550	-
Balance as of December 31, 2013	10,077	387,432	(10,725)	(212,781)	174,003	6,492
Amortization of stock-based awards	780	-	-	-	780	-
Tax benefits related to stock-based awards	49	-	-	-	49	-
Other	(114)	-	-	-	(114)	-
Net income for the year	-	32,520	-	-	32,520	1,095
Dividends - common shares	-	(11,568)	-	-	(11,568)	(248)
Other comprehensive income	-	-	(8,232)	-	(8,232)	(674)
Acquisitions, at cost	-	-	-	(13,183)	(13,183)	-
Dispositions	-	-	-	144	144	-
Balance as of December 31, 2014	10,792	408,384	(18,957)	(225,820)	174,399	6,665

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

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 manager Exxon Mobil Corporation.

The Corporation's principal business is energy, involving the worldwide exploration, production, transportation and sale of crude oil and gas (Upstream) and the manufacture, transportation and sale of petroleum products (Downstream). The Corporation is also a major world 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 reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years' data has been reclassified in certain cases to conform to the 2014 presentation basis.

1. Summary of Accounting Policies

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

Amounts representing the Corporation's interest in entities that it does not control, but over which it exercises significant 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 facts indicate that a majority-owned investment is not controlled and therefore should be accounted for using the equity method of accounting. Such factors occur where the minority shareholders are granted by law or by contract substantive participating rights. These include the right to participate in operating policies, expense budgets, financing and investment plans, and management compensation and succession plans.

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

Evidence of loss in value that might indicate impairment of investments in companies accounted for on the equity method is assessed to determine if such evidence represents a loss in value of the Corporation's investment that is other than temporary. Examples of key inc

include a history of operating losses, negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, financial condition and prospects for the investee's business segment or geographic region. If evidence of an other than temporary loss in fair value below carrying amount is determined, an impairment is recognized. In the absence of market prices for the investment, discounted cash flows used to assess fair value.

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

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

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

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

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

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

Fair Value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2 and 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

Inventories. Crude oil, products and merchandise inventories are carried at the lower of current market value or cost (generally determined by the last-in, first-out method – LIFO). Inventory costs include expenditures and other charges (including depreciation) directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are recognized 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 predetermined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life and obsolescence into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

The Corporation uses the “successful efforts” method to account for its exploration and production activities. Under this method, costs are accumulated on a field-by-field basis. Costs 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 has found a sufficient quantity of reserves to justify completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operational viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred. Development costs including costs of productive wells and development 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 and development costs associated with productive depletable extractive properties are amortized using unit-of-production rates based on the amount of proved developed reserves of oil, gas and other minerals that are estimated to be recoverable using existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

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

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

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

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

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are reviewed based on the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that are individually significant are aggregated by groups and amortized based on 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 substantial obligation for future performance by the Corporation.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

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

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

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

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

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 model for all contracts with customers, eliminates industry specific requirements, and expands disclosure requirements. The standard is required to be adopted beginning January 1, 2017. 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 cumulative effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their carrying values by \$10.6 billion and \$21.2 billion at December 31, 2014, and 2013, respectively.

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

	2014 (billions of dollars)
Petroleum products	4.1
Crude oil	4.6
Chemical products	2.9
Gas/other	0.8
Total	12.4

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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	Tot
Balance as of December 31, 2011	4,168	(13,291)	-	(9,
Current period change excluding amounts reclassified from accumulated other comprehensive income	842	(3,402)	-	(2,
Amounts reclassified from accumulated other comprehensive income	(2,600)	2,099	-	(
Total change in accumulated other comprehensive income	(1,758)	(1,303)	-	(3,
Balance as of December 31, 2012	<u>2,410</u>	<u>(14,594)</u>	<u>-</u>	<u>(12,</u>
Balance as of December 31, 2012	2,410	(14,594)	-	(12,
Current period change excluding amounts reclassified from accumulated other comprehensive income	(3,233)	2,963	-	(
Amounts reclassified from accumulated other comprehensive income	(23)	1,752	-	1,
Total change in accumulated other comprehensive income	(3,256)	4,715	-	1,
Balance as of December 31, 2013	<u>(846)</u>	<u>(9,879)</u>	<u>-</u>	<u>(10,</u>
Balance as of December 31, 2013	(846)	(9,879)	-	(10,
Current period change excluding amounts reclassified from accumulated other comprehensive income	(5,258)	(4,132)	(63)	(9,
Amounts reclassified from accumulated other comprehensive income	152	1,066	3	1,
Total change in accumulated other comprehensive income	(5,106)	(3,066)	(60)	(8,
Balance as of December 31, 2014	<u>(5,952)</u>	<u>(12,945)</u>	<u>(60)</u>	<u>(18,</u>
Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)		2014	2013	2
		<i>(millions of dollars)</i>		
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	(152)	23		
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs (1)	(1,571)	(2,616)		
Realized change in fair value of stock investments included in net income (Statement of Income line: Other income)	(5)	-		
<i>(1) These accumulated other comprehensive income components are included in the computation of net periodic pension cost. (See Note 17, Pension and Other Postretirement Benefits for additional details.)</i>				
Income Tax (Expense)/Credit For Components of Other Comprehensive Income		2014	2013	
		<i>(millions of dollars)</i>		
Foreign exchange translation adjustment	292	218		
Postretirement benefits reserves adjustment (excluding amortization)	2,009	(1,540)		
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(460)	(796)		
Unrealized change in fair value of stock investments	34	-		
Realized change in fair value of stock investments included in net income	(2)	-		
Total	<u>1,873</u>	<u>(2,118)</u>		

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Cash Flow Information

The Consolidated Statement of Cash Flows provides information about changes in cash and cash equivalents. Highly liquid investments 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 non-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. 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 Services (Bahamas) Ltd. was assigned to a consolidated ExxonMobil affiliate. This note is no longer classified as third party long-term debt. The 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
	(millions of dollars)	
Cash payments for interest	380	426
Cash payments for income taxes	18,085	25,066

6. Additional Working Capital Information

	Dec. 31 2014	I
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of \$113 million and \$112 million	18,541	
Other, less reserves of \$48 million and \$28 million	9,468	
Total	<u>28,009</u>	
Notes and loans payable		
Bank loans	473	
Commercial paper	16,225	
Long-term debt due within one year	770	
Total	<u>17,468</u>	
Accounts payable and accrued liabilities		
Trade payables	25,286	
Payables to equity companies	6,589	
Accrued taxes other than income taxes	3,290	
Other	7,062	
Total	<u>42,227</u>	

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 respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

7. Equity Company Information

The summarized financial information below includes amounts related to certain less-than-majority-owned companies and majority-owned subsidiaries where minority shareholders possess the right to participate in significant management decisions (see Note 1). These compa

primarily engaged in oil and gas exploration and production, natural gas marketing, and refining operations in North America; natural gas exploration, production and distribution, and downstream operations in Europe; and exploration, production, liquefied natural gas 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 value of an equity investment and its underlying equity in the net assets of the affiliate are assigned to the practicable to specific assets and liabilities based on the company's analysis of the factors giving rise to the difference. The amortization 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 for years 2014, 2013 and 2012, respectively.

In 2013 and 2014, the Corporation and Rosneft established various entities to conduct exploration and research activities. Per disproportionate funding will result in the Corporation recognizing, during the early phases of the projects, an investment that is larger than the equity share in these entities. These joint ventures are considered Variable Interest 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 United States imposed sanctions relating to the Russian energy sector. In compliance with the sanctions and all general and specific licenses, prohibited activities involving crude oil in Russia in the Black Sea, Arctic regions, and onshore western Siberia have been wound down. The Corporation's maximum exposure to losses in these joint ventures as of December 31, 2014, is \$1.0 billion.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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	D
	<i>(millions of dollars)</i>	
Companies carried at equity in underlying assets		
Investments	20,017	
Advances	9,818	
Total equity company investments and advances	29,835	
Companies carried at cost or less and stock investments carried at fair value		526
Long-term receivables and miscellaneous investments at cost or less, net of reserves of \$2,662 million and \$2,938 million	4,878	
Total	35,239	
	73	

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

9. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	December 31, 2014		December 31, 2013	
	Cost	Net	Cost	N
	<i>(millions of dollars)</i>			
Upstream	347,170	205,308	336,359	1:
Downstream	53,327	22,639	54,456	:
Chemical	30,717	14,918	29,487	
Other	15,575	9,803	14,215	
Total	446,789	252,668	434,517	2:

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

Accumulated depreciation and depletion totaled \$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 \$344 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 assets are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regarding factors such as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations incurred in the current period were Level 3 fair value measurements. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserves are produced. Over time, the liabilities are accreted for the change in their present value.

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

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

	2014
	<i>(millions of dollars)</i>
Beginning balance	12,988
Accretion expense and other provisions	871
Reduction due to property sales	(151)
Payments made	(724)
Liabilities incurred	122
Foreign currency translation	(908)
Revisions	1,226
Ending balance	13,424

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

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

Change in capitalized suspended exploratory well costs:

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

Period end capitalized suspended exploratory well costs:

	2014	2013
	(millions of dollars)	
Capitalized for a period of one year or less	1,095	293
Capitalized for a period of between one and five years	1,659	1,705
Capitalized for a period of between five and ten years	544	470
Capitalized for a period of greater than ten years	289	239
Capitalized for a period greater than one year - subtotal	<u>2,492</u>	<u>2,414</u>
Total	<u>3,587</u>	<u>2,707</u>

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

	2014	2013
Number of projects with first capitalized well drilled in the preceding 12 months	8	8
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	53	50
Total	<u>61</u>	<u>58</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Of the 53 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2014, 15 projects were still in the process of drilling in the preceding 12 months or exploratory activity planned in the next two years, while the remaining 38 projects are those with exploratory activity progressing toward development. The table below 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		

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. Leased Facilities

At December 31, 2014, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering 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

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

	2014	2013
	(millions of dollars)	
Rental cost	4,077	3,841
Less sublease rental income	52	44
Net rental cost	<u>4,025</u>	<u>3,797</u>

12. Earnings Per Share

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

13. Financial Instruments and Derivatives

Financial Instruments. The fair value of financial instruments is determined by reference to observable market data and other valuation techniques as appropriate. The only category of financial instruments where the difference between fair value and recorded book value is notable is long-term debt. The estimated fair value of total long-term debt, excluding capitalized lease obligations, was \$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 31, 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 first 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 \$6.8 billion million.

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. As a result, the Corporation makes limited use of derivatives to mitigate the impact of such changes. The Corporation does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features. When the Corporation does enter into derivative transactions, it is to offset exposures associated with interest rates, foreign currency exchange rates and hydrocarbon prices that arise from existing assets, liabilities and forecasted transactions.

The estimated fair value of derivative instruments outstanding and recorded on the balance sheet was a net asset of \$75 million at year-end 2014 and a net asset of \$1 million at year-end 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 in 2014, 2013 and 2012, respectively. Income statement effects associated with derivatives are usually recorded either in "Sales and other operating revenue" or "Crude oil and product purchases."

The Corporation believes there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity resulting from the derivative activities described above.

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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 exchange rates of amounts 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. The 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 in each of the four years 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 unused 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 (millions of dollars)	2013
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	<u>11,653</u>	<u>6,891</u>

(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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the Incentive Program is 220 million. Awards that are forfeited, expire or are settled in cash, do not count against this maximum limit. The

Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2014, remaining shares 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 (non-common stock and restricted (nonvested) common stock units were granted in 2014, 2013 and 2012, respectively. Compensation expense for awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years, 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

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

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2014.

	2014	Weighted Average Grant-Date Fair Value per Sh
	Shares (thousands)	(dollars)
Restricted stock and units outstanding		
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	<u>44,439</u>	<u>81.45</u>
Value of restricted stock and units	2014	2013
Grant price (dollars)	95.20	94.47
Value at date of grant:		(millions of dollars)
Restricted stock and units settled in stock	858	843
Units settled in cash	73	76
Total value	<u>931</u>	<u>919</u>

As of December 31, 2014, there was \$2,339 million of unrecognized compensation cost related to the nonvested restricted awards. This is expected to be recognized over a weighted-average period of 4.5 years. The compensation cost charged against income for the restricted stock and restricted stock units was \$831 million, \$854 million and \$854 million for 2014, 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 periods, 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 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 legal proceedings. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition and disclosure of these contingencies. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a probable loss and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is more likely than any other amount, then the minimum of the range is accrued. The Corporation does not record liabilities when the likelihood that a loss will be incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss. For purposes of our contingency disclosures, "significant" includes legal matters as well as other matters which management believes should be disclosed. ExxonMobil will continue to defend itself vigorously in all legal matters. Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a material adverse effect upon the Corporation's operations, financial condition, or future 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 performance under contracts. Where guarantees for environmental remediation and other similar matters do not have a stated cap, the amounts reflect management's estimate of the maximum potential exposure.

	Dec. 31, 2014	
	Equity Company Obligations (1)	Other Third-Party Obligations
Guarantees		
Debt-related	3,506	41

Other	2,920	3,982
Total	6,426	4,023

(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 Papua New Guinea Liquefied Natural Gas project. On February 4, 2015, the obligations under this guarantee were terminated per the term loan agreement.

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

	Payments Due by Period		
	2016-		2020 and
	2015	2019	Beyond
(millions of dollars)			

Unconditional purchase obligations (1)	150	608	337
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(1) *Undiscounted obligations of \$1,095 million mainly pertain to pipeline throughput agreements and include \$433 million of obligations to companies. The present value of these commitments, which excludes imputed interest of \$168 million, totaled \$927 million.*

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In accordance with a nationalization decree issued by Venezuela's president in February 2007, by May 1, 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. This Project had been operated and owned by ExxonMobil affiliates holding a 41.67 percent ownership interest in the Project. The decree also required conversion of the Cerro Negro Project into a "mixed enterprise" and an increase in PdVSA's or one of its affiliate's ownership interest in the Project, with the stipulation that if ExxonMobil refused to accept the terms for the formation of the mixed enterprise within a specified period of time, the government would "directly assist" the activities carried out by the joint venture. ExxonMobil refused to accede to the terms proffered by the government, and on June 27, 2010, the government expropriated ExxonMobil's 41.67 percent interest in the Cerro Negro Project.

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID) invoking ICSID jurisdiction under Venezuela's Investment Law and the Netherlands-Venezuela Bilateral Investment Treaty. The ICSID Tribunal issued a decision on June 10, 2010, finding that it had jurisdiction to proceed on the basis of the Netherlands-Venezuela Bilateral Investment Treaty. On October 9, 2014, the ICSID Tribunal issued its final award finding in favor of the ExxonMobil affiliates and awarding \$269 million as of the date of expropriation, June 27, 2007, and interest from that date at 3.25% compounded annually until the date of payment. The Tribunal also noted that one of the Cerro Negro Project agreements provides a mechanism to prevent double recovery between the award and all or part of an earlier award of \$908 million to an ExxonMobil affiliate, Mobil Cerro Negro, Ltd., against PdVSA and a Venezuelan affiliate, PdVSA CN, in an arbitration under the rules of the International Chamber of 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 the 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 on 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 the 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 ICC award to PdVSA at the same time as payment is made to the ExxonMobil affiliates for the ICSID award and that provides for interest on the amount to be repaid. Thereafter, pursuant to ICSID arbitration rules, the ICSID award was stayed pending further action by the Tribunal. On October 27, 2014, ExxonMobil filed a response with ICSID that contests the application for revision of that award on both legal and jurisdictional grounds. On February 2, 2015, the Republic of Venezuela filed an application to annul the ICSID award. The application asserted 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. Upon 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 applications 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 the resolution to have a material effect upon the Corporation's operating financial condition.

An affiliate of ExxonMobil is one of the Contractors under a Production Sharing Contract (PSC) with the Nigerian National Petroleum Corporation (NNPC) covering the Erha block located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the block and holds a 56.25 percent interest under the PSC. The Contractors are in dispute with NNPC regarding NNPC's lifting of crude oil in excess of its entitlement under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuja, Nigeria, under the Nigerian Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholding the Contractors' position in material respects and awarding damages to the Contractors jointly in an amount of approximately \$1.8 billion plus \$234 million in accrued interest. The Contractors petitioned a Nigerian federal court for enforcement of the award, and NNPC petitioned the same court to have the award set aside.

On May 22, 2012, the court set aside the award. The Contractors have appealed that judgment. In June 2013, the Contractors filed a lawsuit NNPC in the Nigerian federal high court in order to preserve their ability to seek enforcement of the PSC in the courts if necessary. In 2014, the Contractors filed suit in the United States District Court for the Southern District of New York to enforce, if necessary, the arb award against NNPC 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 of the outcome of enforcement proceedings, the Corporation does not expect 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 2014	
	U.S.		Non-U.S.			
	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	
Long-term rate of compensation increase	5.75	5.75	5.30	5.40	5.75	
(millions of dollars)						
Change in benefit obligation						
Benefit obligation at January 1	17,304	19,779	27,357	28,670	7,868	
Service cost	677	801	590	697	140	
Interest cost	807	749	1,138	1,076	383	
Actuarial loss/(gain)	3,192	(1,520)	4,929	(1,454)	1,522	
Benefits paid (1) (2)	(1,427)	(2,520)	(1,366)	(1,311)	(525)	
Foreign exchange rate changes	-	-	(2,540)	(284)	(48)	
Amendments, divestments and other	(24)	15	(61)	(37)	96	
Benefit obligation at December 31	20,529	17,304	30,047	27,357	9,436	
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 discount rate determined by use of a yield curve based on high-quality, noncallable bonds with cash flows that match estimated outflows for payments. For major non-U.S. plans, the discount rate is determined by using bond portfolios with an average maturity approximating 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 20 subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by \$91 million in the postretirement benefit obligation by \$1,070 million. A one-percentage-point 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 2014	
	U.S.		Non-U.S.			
	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	
Actual return on plan assets	1,497	617	3,153	1,604	41	
Foreign exchange rate changes	-	-	(1,738)	(270)	-	
Company contribution	1,476	101	554	919	31	
Benefits paid (1)	(1,248)	(2,171)	(912)	(869)	(224)	
Other	-	11	(245)	(191)	-	
Fair value at December 31	12,915	11,190	20,095	19,283	468	

(1) Benefit payments for funded plans.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The funding levels of all qualified pension plans are in compliance with standards set by applicable law or regulation. As shown in the table certain smaller U.S. pension plans and a number of non-U.S. pension plans are not funded because local tax conventions and regulatory practices do not encourage funding of these plans. All defined benefit pension obligations, regardless of the funding status of the underlying plans, are supported by the financial strength of the Corporation or the respective sponsoring affiliate.

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

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

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

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

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

	Pension Benefits			Other Postretirement Benefits		
	U.S.		Non-U.S.			
	2014	2013	2012	2014	2013	2012
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31						
Discount rate	5.00	4.00	5.00	4.30	3.80	4.00
Long-term rate of return on funded assets	7.25	7.25	7.25	6.30	6.40	6.60
					(percent)	

Long-term rate of compensation increase	5.75	5.75	5.75	5.40	5.50	5.40	5.75	5.75
Components of net periodic benefit cost <i>(millions of dollars)</i>								
Service cost	677	801	665	590	697	648	140	176
Interest cost	807	749	820	1,138	1,076	1,145	383	352
Expected return on plan assets	(799)	(835)	(789)	(1,193)	(1,128)	(1,109)	(37)	(41)
Amortization of actuarial loss/(gain)	409	646	576	628	852	844	116	228
Amortization of prior service cost	8	7	7	120	117	117	14	21
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

(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)
Amortization of actuarial (loss)/gain	(685)	(1,369)	(909)	(628)	(874)	(2,384)	(116)	(228)
Prior service cost/(credit)	(25)	-	-	(70)	30	71	-	-
Amortization of prior service (cost)/credit	(8)	(7)	(7)	(120)	(117)	(117)	(14)	(21)
Foreign exchange rate changes	-	-	-	(688)	(155)	271	(8)	(10)
Total recorded in other comprehensive income	1,776	(2,678)	969	1,463	(3,054)	(253)	1,380	(1,549)
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)

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

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

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

The Corporation's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in various classes and broad diversification to reduce the risk of the portfolio. The benefit plan assets are primarily invested in passive equity and fixed index funds to diversify risk while minimizing costs. The equity funds hold ExxonMobil stock only to the extent necessary to replicate the equity index. The fixed income funds are largely invested in high-quality corporate and government debt securities.

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

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

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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						Non-U.S. Pension							
Fair Value Measurement at December 31, 2014, Using:						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⁾	-						
Non-U.S.	-	2,144 ⁽¹⁾	-	2,144	229 ⁽²⁾	3,776 ⁽¹⁾	-						
Private equity	-	-	562 ⁽³⁾	562	-	-	-			535 ⁽³⁾			
Debt securities													
Corporate	-	4,841 ⁽⁴⁾	-	4,841	-	2,686 ⁽⁴⁾	-						
Government	-	2,890 ⁽⁴⁾	-	2,890	249 ⁽⁵⁾	9,050 ⁽⁴⁾	-						
Asset-backed	-	5 ⁽⁴⁾	-	5	-	146 ⁽⁴⁾	-						
Real estate funds	-	-	-	-	-	-	-			57 ⁽⁶⁾			
Cash	-	131 ⁽⁷⁾	-	131	25	31 ⁽⁸⁾	-						
Total at fair value	-	12,342	562	12,904	503	18,973	592						
Insurance contracts at contract value				11									
Total plan assets				12,915									

- (1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are 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 Public Offerings.
- (4) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transaction.
- (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 input.
- (8) For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a Level 2 input.

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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)			
(millions of dollars)					

Insurance contracts at contract value	12
Total plan assets	<u>11,190</u>

- (1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are 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 Public Offerings.
- (4) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transaction.
- (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 input.
- (8) For cash balances that are subject to withdrawal penalties or other adjustments, the fair value is treated as a Level 2 input.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Asset category:	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)		
(millions of dollars)					
Equity securities					
U.S.	-	157 (1)	-		
Non-U.S.	-	149 (1)	-		
Private equity	-	-	9 (2)		
Debt securities					
Corporate	-	129 (3)	-		
Government	-	168 (3)	-		
Asset-backed	-	4 (3)	-		
Cash	-	4	-		
Total at fair value	<u>-</u>	<u>611</u>	<u>9</u>		

- (1) For U.S. and non-U.S. equity securities held in the form of fund units that are redeemable at the measurement date, the unit value is treated as a Level 2 input. The fair value of the securities owned by the funds is based on observable quoted prices on active exchanges, which are inputs.
- (2) For private equity, fair value is generally established by using revenue or earnings multiples or other relevant market data including Public Offerings.
- (3) For corporate, government and asset-backed debt securities, fair value is based on observable inputs of comparable market transaction.

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

	2013				
	Pension			Other	
	U.S.		Non-U.S.		Postretiremen t Private Equity
	Private Equity	Equity	Private Equity	Real Estate	
(millions of dollars)					
Fair value at January 1	489	448	293		
Net realized gains/(losses)	(1)	11	(13)		
Net unrealized gains/(losses)	86	57	10		

Net purchases/(sales)	(51)	(14)	(154)
Fair value at December 31	523	502	136

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.	2013	2014	Non-U.S.
(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	
Accumulated benefit obligation	14,493	12,342	4,590	
Fair value of plan assets	12,915	11,189	3,890	
For unfunded pension plans:				
Projected benefit obligation	3,024	2,567	7,839	
Accumulated benefit obligation	1,892	1,647	6,573	
Other Postretirement Benefits				
	Pension 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
Prior service cost (2)	6	105

- (1) The Corporation amortizes the net balance of actuarial losses/(gains) as a component of net periodic benefit cost over the average remaining service period of active plan participants.
 (2) The Corporation amortizes prior service cost on a straight-line basis as permitted under authoritative guidance for defined benefit pension and other postretirement benefit plans.

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Rece
(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 used to identify these reportable segments are based on the nature of the operations that are undertaken by each segment. The Upstream segment is organized and operates to explore for and produce crude oil and natural gas. The Downstream segment is organized and operates to manufacture and sell petroleum products. The Chemical segment is organized and operates to manufacture and sell petrochemicals. These segments are 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 activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Corporation's operating decision maker to make decisions about resources to be allocated to the segment and to assess its performance; and (3) for which financial information is available.

Earnings after income tax include transfers at estimated market prices.

Non-U.S.	42,550	47,965
Total	51,630	57,711
Theoretical tax	18,071	20,199
Effect of equity method of accounting	(4,663)	(4,874)
Non-U.S. taxes in excess of theoretical U.S. tax	5,442	10,528
U.S. tax on non-U.S. operations	5	37
State taxes, net of federal tax benefit	(324)	258
Other	(516)	(1,885)
Total income tax expense	18,015	24,263
Effective tax rate calculation		
Income taxes	18,015	24,263
ExxonMobil share of equity company income taxes	5,678	6,061
Total income taxes	23,693	30,324
Net income including noncontrolling interests	33,615	33,448
Total income before taxes	57,308	63,772
Effective income tax rate	41%	48%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

Tax effects of temporary differences for:	2014	2
	(millions of dollars)	
Property, plant and equipment	51,643	
Other liabilities	4,359	
Total deferred tax liabilities	<u>56,002</u>	
Pension and other postretirement benefits	(8,140)	
Asset retirement obligations	(6,162)	
Tax loss carryforwards	(4,099)	
Other assets	(6,446)	
Total deferred tax assets	<u>(24,847)</u>	(
Asset valuation allowances	2,570	
Net deferred tax liabilities	<u>33,725</u>	

In 2014, asset valuation allowances of \$2,570 million increased by \$79 million and included additional net provisions of \$340 million and effective currency translation of \$(261) million.

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

Balance sheet classification	2014	2
	(millions of dollars)	
Other current assets	(2,001)	
Other assets, including intangibles, net	(3,955)	
Accounts payable and accrued liabilities	451	
Deferred income tax liabilities	<u>39,230</u>	
Net deferred tax liabilities	<u>33,725</u>	

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

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 favorably 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 a 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 of resolution for tax positions since such timing is not entirely within the control of the Corporation. It is reasonably possible that the total amount of unrecognized tax benefits could increase by up to 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 credit of \$207 million, reflecting the effect of credits from the favorable resolution of prior year tax positions. The Corporation incurred \$46 in interest expense in 2012. The related interest payable balances were \$205 million and \$156 million at December 31, 2014, and 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 its Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for consolidated and equity companies totaled \$3,223 million in 2014, \$886 million in 2013, and \$2,832 million in 2012. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board

	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania
Results of Operations						(millions of dollars)

Net capitalized costs for equity companies	4,093	-	1,467	-	5,160	-
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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 asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting in changes in cost estimates or abandonment date. Total consolidated costs incurred in 2014 were \$29,115 million, down \$4,508 million from 2013 primarily to lower property acquisition costs and development costs. In 2013 costs were \$33,623 million, up \$2,477 million from 2012 primarily to higher property acquisition costs partially offset by lower exploration costs. Total equity company costs incurred in 2014 were \$3,829 million, up \$335 million from 2013, due primarily to exploration costs.

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

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 economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates renewal is reasonably certain. In some cases, substantial new investments in additional wells and related facilities will be required to develop these proved reserves.

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

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

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

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

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the fiscal terms in the agreement. The production and reserves that we report for these types of arrangements typically vary inversely with oil and price changes. As oil and gas prices increase, the cash flow and value received by the company increase; however, the production volume reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2014 that were 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 6 billion cubic feet = 1 million barrels).

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

Crude oil and natural gas liquids and natural gas production quantities shown are the net volumes withdrawn from ExxonMobil's oil & reserves. The natural gas quantities differ from the quantities of gas delivered for sale by the producing function as reported in the Op 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, extensive discoveries in Canada and the United States.

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

	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.
(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
Revisions	25	33	14	20	(10)	5	87	3	265	(29)
Improved recovery	6	-	-	-	1	-	7	-	-	-
Purchases	163	-	20	-	-	-	183	36	-	-
Sales	(15)	(1)	(8)	(58)	-	-	(82)	(4)	-	-
Extensions/discoveries	166	138	8	41	9	-	362	164	234	-
Production	(100)	(18)	(62)	(173)	(117)	(12)	(482)	(73)	(45)	(25)
December 31, 2012	1,905	270	289	1,293	1,604	163	5,524	1,031	3,560	599

Proportional interest in proved reserves of equity companies

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

	Crude Oil and Natural Gas Liquids							Bitumen Canada/ South Amer. (2)	Synthetic Oil Canada/ South Amer. (3)		
	United States	Canada/ South Amer. (1)		Europe	Africa	Asia	Australia/ Oceania				
(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		
Equity companies	264	-	28	-	1,423	-	1,715	-	-		
Proved undeveloped reserves, as of December 31, 2012											
Consolidated subsidiaries	921	163	77	497	682	134	2,474	3,017	-		
Equity companies	84	-	-	-	303	-	387	-	-		
Total liquids proved reserves at December 31, 2012	2,758	287	373	1,501	3,488	250	8,657	3,560	599		
Proved developed reserves, as of December 31, 2013											
Consolidated subsidiaries	1,469	126	249	945	1,663	105	4,557	1,810	579		
Equity companies	268	-	27	-	1,292	-	1,587	-	-		
Proved undeveloped reserves, as of December 31, 2013											
Consolidated subsidiaries	1,068	177	51	449	638	131	2,514	1,820	-		
Equity companies	77	-	1	-	294	-	372	-	-		
Total liquids proved reserves at December 31, 2013	2,882	303	328	1,394	3,887	236	9,030	3,630	579		
Proved developed reserves, as of December 31, 2014											
Consolidated subsidiaries	1,502	111	205	894	1,615	112	4,439	2,122	534		
Equity companies	269	-	26	-	1,188	-	1,483	-	-		
Proved undeveloped reserves, as of December 31, 2014											
Consolidated subsidiaries	1,234	190	42	401	651	99	2,617	2,111	-		
Equity companies	75	-	1	-	331	-	407	-	-		
Total liquids proved reserves at December 31, 2014	3,080	301	274	1,295	3,785	211	8,946 (4)	4,233	534		

- (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 of 52 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 million 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 developed 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 million 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 reserves of 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 Item 2. Properties in ExxonMobil's 2014 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas				Oil-Equiv Total
	United	Canada/ South	Australia/ Oceania	Canada/ South Amer. (2)	

December 31, 2014	25,987	1,226	2,383	811	5,460	7,276	43,143	19,0
Proportional interest in proved reserves of equity companies								
January 1, 2014	281	-	8,884	-	18,514	-	27,679	6,5
Revisions	5	-	117	-	110	-	232	1
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	-
Production	(15)	-	(583)	-	(1,119)	-	(1,717)	(4
December 31, 2014	272	-	8,418	-	17,505	-	26,195	6,2
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,2

(1) Includes total proved reserves attributable to Imperial Oil Limited of 488 billion cubic feet in 2012, 678 billion cubic feet in 2013 and 691 billion cubic feet in 2014, as well as proved 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 cubic 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.

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Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equiva lent Total All Product (millions of equivalen	
	United States	Canada/ South Amer. (1)					Australia/ Oceania Total (billions of cubic feet)		
		Europe	Africa	Asia	Australia/ Oceania Total				
Proved developed reserves, as of									
December 31, 2012									
Consolidated subsidiaries	14,471	670	2,526	814	5,150	1,012	24,643	9,3	
Equity companies	126	-	7,057	-	18,431	-	25,614	5,9	
Proved undeveloped reserves, as of									
December 31, 2012									
Consolidated subsidiaries	11,744	255	723	115	695	6,556	20,088	8,8	
Equity companies	29	-	2,478	-	1,239	-	3,746	1,0	
Total proved reserves at December 31, 2012	26,370	925	12,784	929	25,515	7,568	74,091	25,1	
Proved developed reserves, as of									
December 31, 2013									
Consolidated subsidiaries	14,655	664	2,189	779	5,241	969	24,497	11,0	
Equity companies	197	-	6,852	-	17,288	-	24,337	5,6	
Proved undeveloped reserves, as of									
December 31, 2013									
Consolidated subsidiaries	11,365	571	621	88	493	6,546	19,684	7,6	
Equity companies	84	-	2,032	-	1,226	-	3,342	9	
Total proved reserves at December 31, 2013	26,301	1,235	11,694	867	24,248	7,515	71,860	25,2	
Proved developed reserves, as of									
December 31, 2014									
Consolidated subsidiaries	14,169	615	1,870	764	5,031	2,179	24,628	11,1	
Equity companies	194	-	6,484	-	16,305	-	22,983	5,3	
Proved undeveloped reserves, as of									
December 31, 2014									
Consolidated subsidiaries	11,818	611	513	47	429	5,097	18,515	7,8	
Equity companies	78	-	1,934	-	1,200	-	3,212	9	
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,2	

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 a first-day-of-the-month average prices, 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 and rehabilitation obligations. The Corporation believes the standardized measure does not provide a reliable estimate of the Corporation's expected future cash flows to be obtained from the development production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may result in significant variability in cash flows from year to year as prices change.

Standardized Measure of Discounted Future Cash Flows	United States	Canada/South America (1)					Australia/Oceania	Total		
		Europe	Africa	Asia	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	1,043,299	1,043,299		
Future production costs	109,325	101,299	17,277	33,398	42,816	26,132	326,636	326,636		
Future development costs	37,504	44,518	16,505	13,363	13,083	11,435	134,435	134,435		
Future income tax expenses	43,772	34,692	23,252	63,246	75,261	21,405	211,903	211,903		
Future net cash flows	59,781	113,401	9,735	50,254	61,331	45,362	330,898	330,898		
Effect of discounting net cash flows at 10%	36,578	82,629	2,097	18,091	35,310	27,610	202,598	202,598		
Discounted future net cash flows	23,203	30,772	7,638	32,163	26,021	17,752	134,698	134,698		
Equity Companies										
As of December 31, 2012										
Future cash inflows from sales of oil and gas	36,043	-	93,563	-	348,026	-	417,632	417,632		
Future production costs	7,040	-	64,988	-	112,980	-	184,908	184,908		
Future development costs	3,708	-	2,569	-	10,780	-	16,057	16,057		
Future income tax expenses	-	-	9,937	-	78,539	-	97,476	97,476		
Future net cash flows	25,295	-	16,069	-	145,727	-	187,091	187,091		
Effect of discounting net cash flows at 10%	14,741	-	8,133	-	76,979	-	99,853	99,853		
Discounted future net cash flows	10,554	-	7,936	-	68,748	-	87,237	87,237		
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	280,254	280,254		

(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)					Australia/Oceania	Total		
		Europe	Africa	Asia	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	1,111,479	1,111,479		
Future production costs	113,571	106,884	18,053	30,960	57,328	22,507	337,902	337,902		
Future development costs	40,702	43,102	15,215	14,300	10,666	10,191	114,259	114,259		
Future income tax expenses	50,144	31,901	17,186	53,766	117,989	16,953	213,002	213,002		
Future net cash flows	71,634	111,490	7,781	47,381	59,499	38,157	360,700	360,700		
Effect of discounting net cash flows at 10%	42,336	78,700	1,278	18,406	34,878	21,266	209,184	209,184		
Discounted future net cash flows	29,298	32,790	6,503	28,975	24,621	16,891	144,771	144,771		
Equity Companies										
As of December 31, 2013										

Future cash inflows from sales of oil and gas	34,957	-	82,539	-	324,666	-	4
Future production costs	8,231	-	60,518	-	107,656	-	1
Future development costs	3,675	-	2,994	-	8,756	-	
Future income tax expenses	-	-	7,237	-	70,887	-	
Future net cash flows	23,051	-	11,790	-	137,367	-	1
Effect of discounting net cash flows at 10%	12,994	-	5,549	-	72,798	-	
Discounted future net cash flows	10,057	-	6,241	-	64,569	-	
 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	 2
 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	1,1
Future production costs	116,929	140,368	14,358	27,917	57,562	20,467	3
Future development costs	42,276	48,525	13,000	14,603	12,591	8,956	1
Future income tax expenses	49,807	36,787	10,651	44,977	102,581	15,050	2
Future net cash flows	74,755	128,543	4,873	37,628	52,151	33,892	3
Effect of discounting net cash flows at 10%	44,101	87,799	(52)	13,831	30,173	17,326	1
Discounted future net cash flows	30,654	40,744	4,925	23,797	21,978	16,566	1
 Equity Companies							
As of December 31, 2014							
Future cash inflows from sales of oil and gas	31,924	-	71,031	-	286,124	-	3
Future production costs	8,895	-	50,826	-	99,193	-	1
Future development costs	3,386	-	2,761	-	11,260	-	
Future income tax expenses	-	-	6,374	-	59,409	-	
Future net cash flows	19,643	-	11,070	-	116,262	-	1
Effect of discounting net cash flows at 10%	10,970	-	5,534	-	61,550	-	
Discounted future net cash flows	8,673	-	5,536	-	54,712	-	
 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	 2

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

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

Consolidated and Equity Interests	2012		Total
	Consolidated Subsidiaries	Share of Equity Method Investees	Consolidated and Equity Interests
			(millions of dollars)
Discounted future net cash flows as of December 31, 2011	152,244	86,560	238,80
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	7,952	531	8,4
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)	(74,7
Development costs incurred during the year	24,596	1,186	25,7
Net change in prices, lifting and development costs	(31,382)	5,656	(25,7
Revisions of previous reserves estimates	3,876	7,018	10,8
Accretion of discount	19,676	8,846	28,5
Net change in income taxes	12,339	463	12,80
Total change in the standardized measure during the year	(14,695)	678	(14,0
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,70
Consolidated and Equity Interests			Total

	Consolidated Subsidiaries	Share of Equity Method Investees	Consolidated and Equi Interes
	(millions of dollars)		
Discounted future net cash flows as of December 31, 2012	137,549	87,238	224,71
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	11,928	48	11,9
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)	(72,4)
Development costs incurred during the year	24,821	1,389	26,2
Net change in prices, lifting and development costs	(32,423)	(5,296)	(37,7)
Revisions of previous reserves estimates	24,353	4,960	29,3
Accretion of discount	20,596	9,830	30,4
Net change in income taxes	996	6,455	7,4
Total change in the standardized measure during the year	1,529	(6,371)	(4,8)
Discounted future net cash flows as of December 31, 2013	139,078	80,867	219,9
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Change in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Consolidated and Equity Interests (continued)

	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equi Interes
	(millions of dollars)		
Discounted future net cash flows as of December 31, 2013	139,078	80,867	219,9
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	3,497	94	3,5
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)	(62,8)
Development costs incurred during the year	24,189	1,453	25,6
Net change in prices, lifting and development costs	(50,672)	(13,165)	(63,8)
Revisions of previous reserves estimates	35,072	3,298	38,3
Accretion of discount	20,098	8,987	29,0
Net change in income taxes	11,848	5,753	17,6
Total change in the standardized measure during the year	(414)	(11,946)	(12,3)
Discounted future net cash flows as of December 31, 2014	138,664	68,921	207,5
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OPERATING SUMMARY (unaudited)

	2014	2013	2012	2011
Production of crude oil, natural gas liquids, bitumen and synthetic oil				
Net production				(thousands of barrels daily)
United States	454	431	418	423
Canada/South America	301	280	251	252
Europe	184	190	207	270
Africa	489	469	487	508
Asia	624	784	772	808
Australia/Oceania	59	48	50	51
Worldwide	2,111	2,202	2,185	2,312
Natural gas production available for sale				
Net production				(millions of cubic feet daily)

United States	3,404	3,545	3,822	3,917
Canada/South America	310	354	362	412
Europe	2,816	3,251	3,220	3,448
Africa	4	6	17	7
Asia	4,099	4,329	4,538	5,047
Australia/Oceania	512	351	363	331
Worldwide	11,145	11,836	12,322	13,162
<hr/>				
Oil-equivalent production (1)		(thousands of oil-equivalent barrels daily)		
	3,969	4,175	4,239	4,506
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Refinery throughput		(thousands of barrels daily)		
United States	1,809	1,819	1,816	1,784
Canada	394	426	435	430
Europe	1,454	1,400	1,504	1,528
Asia Pacific	628	779	998	1,180
Other Non-U.S.	191	161	261	292
Worldwide	4,476	4,585	5,014	5,214
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Petroleum product sales (2)				
United States	2,655	2,609	2,569	2,530
Canada	496	464	453	455
Europe	1,555	1,497	1,571	1,596
Asia Pacific and other Eastern Hemisphere	1,085	1,206	1,381	1,556
Latin America	84	111	200	276
Worldwide	5,875	5,887	6,174	6,413
Gasoline, naphthas	2,452	2,418	2,489	2,541
Heating oils, kerosene, diesel oils	1,912	1,838	1,947	2,019
Aviation fuels	423	462	473	492
Heavy fuels	390	431	515	588
Specialty petroleum products	698	738	750	773
Worldwide	5,875	5,887	6,174	6,413
<hr/>				
Chemical prime product sales (3)		(thousands of metric tons)		
United States	9,528	9,679	9,381	9,250
Non-U.S.	14,707	14,384	14,776	15,756
Worldwide	24,235	24,063	24,157	25,006

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

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

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

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

SIGNATURES

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

EXXON MOBIL CORPORATION

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

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints Randall M. Ebner, Leonard M. Fox and Catherine C. Sh each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Comm granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act an requisite and necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratify confirming all that said attorneys-in-fact and agents or any of them, or their or his or her substitute or substitutes, may lawfully do o 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 behalf of the registrant and in the capacities indicated and on February 25, 2015.

/s/ <u>REX W. TILLERSON</u> (Rex W. Tillerson)	Chairman of the Board (Principal Executive Officer)
/s/ <u>MICHAEL J. BOSKIN</u> (Michael J. Boskin)	Director
/s/ <u>PETER BRABECK-LETMATHE</u> (Peter Brabeck-Letmathe)	Director
/s/ <u>URSULA M. BURNS</u> (Ursula M. Burns)	Director
/s/ <u>LARRY R. FAULKNER</u> (Larry R. Faulkner)	Director
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/s/ <u>JAY S. FISHMAN</u> (Jay S. Fishman)	Director
/s/ <u>HENRIETTA H. FORE</u> (Henrietta H. Fore)	Director
/s/ <u>KENNETH C. FRAZIER</u> (Kenneth C. Frazier)	Director
/s/ <u>WILLIAM W. GEORGE</u> (William W. George)	Director
/s/ <u>SAMUEL J. PALMISANO</u> (Samuel J. Palmisano)	Director
/s/ <u>STEVEN S REINEMUND</u> (Steven S Reinemund)	Director
/s/ <u>WILLIAM C. WELDON</u> (William C. Weldon)	Director
/s/ <u>ANDREW P. SWIGER</u> (Andrew P. Swiger)	Senior Vice President (Principal Financial 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 (incor by reference to Exhibit 3(i) to the 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 A 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-K 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 on 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 for 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 Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors.*
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 on Form 10-Q for the quarter ended September 30, 2011).*
10(iii)(g.3)	1984 Mobil Compensation Management Retention Plan (incorporated by reference to Exhibit 10(iii)(g.3) to the 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.

INDEX TO EXHIBITS – (continued)

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 subsidiaries for which consolidated or unconsolidated financial statements are required to be filed. The registrant agrees to furnish a copy such instrument to the Securities and Exchange Commission upon request.