2016

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, 2016

or

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

For the transition period from to

Commission File Number 1-2256

EXXON MOBIL CORPORATION

(Exact name of registrant as specified in its charter)

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

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 444-1000

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, without par value (4,146,513,819 shares outstanding at January 31, 2017)	**New York Stock Exchange**

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

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer ☐

Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $93.74 on the New York Stock Exchange composite tape, was in excess of $388 billion.

Documents Incorporated by Reference: Proxy Statement for the 2017 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2016

TABLE OF CONTENTS

PART I

PART II

PART III

PART IV

PART I

ITEM 1. BUSINESS

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

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

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels, as well as projects to monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions, and expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2016 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.9 billion, of which $3.5 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to remain relatively flat at approximately $5 billion in 2017 and 2018. Capital expenditures are expected to account for approximately 30 percent of the total.

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

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

ExxonMobil has a long-standing commitment to the development of proprietary technology. We have a wide array of research programs designed to meet the needs identified in each of our business segments. Information on Company-sponsored research and development spending is contained in "Note 3: Miscellaneous Financial Information" of the Financial Section of this report. ExxonMobil held nearly 12 thousand active patents worldwide at the end of 2016. For technology licensed to third parties, revenues totaled approximately $104 million in 2016. 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 71.1 thousand, 73.5 thousand, and 75.3 thousand at years ended 2016, 2015 and 2014, respectively. Regular employees are defined as active executive, management, professional, technical and wage employees who work full time or part time for the Corporation and are covered by the Corporation's benefit plans and programs. Regular employees do not include employees of the company-operated retail sites (CORS). The number of CORS employees was 1.6 thousand, 2.1 thousand, and 8.4 thousand at years ended 2016, 2015 and 2014, respectively. The decrease in CORS employees reflects the multi-year transition of the company-operated retail network to a more capital-efficient Branded Wholesaler model.

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

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

ITEM 1A. RISK FACTORS

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

Supply and Demand

The oil, gas, and petrochemical businesses are fundamentally commodity businesses. This means ExxonMobil's operations and earnings may be significantly affected by changes in oil, gas, and petrochemical prices and by changes in margins on refined products. Oil, gas, petrochemical, and product prices and margins in turn depend on local, regional, and global events or conditions that affect supply and demand for the relevant commodity. Any material decline in oil or natural gas prices could have a material adverse effect on certain of the Company's operations, especially in the Upstream segment, financial condition and proved reserves. On the other hand, a material increase in oil or natural gas prices could have a material adverse effect on certain of the Company's operations, especially in the Downstream and Chemical segments.

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

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

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

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

Government and Political Factors

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

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

Restrictions on doing business. 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 may be 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 regulatory frameworks for oil and gas development. Lack of legal certainty exposes our operations to increased risk of adverse or unpredictable actions by government officials, and also makes it more difficult for us to enforce our contracts. In some cases these risks can be partially offset by agreements to arbitrate disputes in an international forum, but the adequacy of this remedy may still depend on the local legal system to enforce an award.

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

- increases in taxes, duties, 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, methane emissions, or hydraulic fracturing);
- adoption of regulations mandating the use of alternative fuels or uncompetitive fuel components;
- adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information, or that could cause us to violate the non-disclosure laws of other countries; and
- government actions to cancel contracts, re-denominate the official currency, renounce or default on obligations, renegotiate terms unilaterally, or expropriate assets.

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

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

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

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

Government sponsorship of alternative energy. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. We are conducting our own research both in-house and by working with more than 80 leading universities around the world, including the Massachusetts Institute of Technology, Princeton University, the University of Texas, and Stanford University. Our research projects focus on developing algae-based biofuels, carbon capture and storage, breakthrough energy efficiency processes, advanced energy-saving materials and other technologies. For example, ExxonMobil is working with Fuel Cell Energy Inc. to explore using carbonate fuel cells to economically capture CO_2 emissions from gas-fired power plants. Our future results may depend in part on the success of our research efforts and on our ability to adapt and apply the strengths of our current business model to providing the energy products of the future in a cost-competitive manner. See "Management Effectiveness" below.

Management Effectiveness

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

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

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

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

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

Research and development. To maintain our competitive position, especially in light of the technological nature of our businesses and the need for continuous efficiency improvement, ExxonMobil’s research and development organizations must be successful and able to adapt to a changing market and policy environment, including developing technologies to help reduce greenhouse gas emissions.

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

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

Preparedness. Our operations may be disrupted by severe weather events, natural disasters, human error, and similar events. For example, hurricanes may damage our offshore production facilities or coastal refining and petrochemical plants in vulnerable areas. Our facilities are designed, constructed, and operated to withstand a variety of extreme climatic and other conditions, with safety factors built in to cover a number of engineering uncertainties, including those associated with wave, wind, and current intensity, marine ice flow patterns, permafrost stability, storm surge magnitude, temperature extremes, extreme rain fall events, and earthquakes. Our consideration of changing weather conditions and inclusion of safety factors in design covers the engineering uncertainties that climate change and other events may potentially introduce. Our ability to mitigate the adverse impacts of these events depends in part upon the effectiveness of our robust facility engineering as well as our rigorous disaster preparedness and response and business continuity planning.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

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 2016

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and equity companies. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. 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. As a result of very low prices during 2016, under the SEC definition of proved reserves, certain quantities of oil and natural gas that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2016. Among the factors that would result in these amounts being recognized again as proved reserves at some point in the future are a recovery in average price levels, a further decline in costs, and / or operating efficiencies. Otherwise, no major discovery or other favorable or adverse event has occurred since December 31, 2016, that would cause a significant change in the estimated proved reserves as of that date.

	Crude Oil	Natural Gas Liquids	Bitumen	Synthetic Oil	Natural Gas	Oil-Equivalent Basis
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million bbls)*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,013	304	-	-	11,927	3,305
Canada/South America *(1)*	79	8	436	564	478	1,167
Europe	146	29	-	-	1,473	420
Africa	679	157	-	-	728	957
Asia	1,733	125	-	-	4,532	2,614
Australia/Oceania	74	31	-	-	3,071	616
Total Consolidated	3,724	654	436	564	22,209	9,079
Equity Companies						
United States	205	5	-	-	144	233
Europe	11	-	-	-	5,804	979
Asia	784	330	-	-	14,067	3,459
Total Equity Company	1,000	335	-	-	20,015	4,671
Total Developed	4,724	989	436	564	42,224	13,750
Undeveloped						
Consolidated Subsidiaries						
United States	1,168	458	-	-	5,859	2,603
Canada/South America *(1)*	162	7	265	-	462	511
Europe	27	4	-	-	186	62
Africa	165	4	-	-	43	176
Asia	1,025	-	-	-	389	1,089
Australia/Oceania	47	27	-	-	4,286	789
Total Consolidated	2,594	500	265	-	11,225	5,230
Equity Companies						
United States	31	5	-	-	67	47
Europe	6	-	-	-	1,820	309
Asia	399	44	-	-	1,167	638
Total Equity Company	436	49	-	-	3,054	994
Total Undeveloped	3,030	549	265	-	14,279	6,224
Total Proved Reserves	7,754	1,538	701	564	56,503	19,974

(1) South America includes proved developed reserves of 29 billion cubic feet of natural gas.

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

The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups; operational outages; reservoir performance; performance of enhanced oil recovery projects; regulatory changes; the impact of fiscal and commercial terms; asset sales; weather events; price effects on production sharing contracts; changes in the amount and timing of capital investments that may vary depending on the oil and gas price environment; and other factors described in Item 1A. Risk Factors.

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 pressures. Furthermore, the Corporation only records proved reserves for projects which have received significant funding commitments by management made toward the development of the reserves. Although the Corporation is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in projections of long-term oil and natural gas price levels. In addition, proved reserves could be affected by an extended period of low prices which could reduce the level of the Corporation's capital spending and also impact our partners' capacity to fund their share of joint projects.

As noted above, certain quantities of oil and natural gas that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2016. Amounts no longer qualifying as proved reserves include the entire 3.5 billion barrels of bitumen at Kearl. In addition, 0.8 billion barrels of oil equivalent across the remainder of North America no longer qualify as proved reserves mainly due to the acceleration of the projected end-of-field-life. Among the factors that would result in these amounts being recognized again as proved reserves at some point in the future are a recovery in average price levels, a further decline in costs, and / or operating efficiencies. Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to ExxonMobil. We do not expect the downward revision of reported proved reserves under SEC definitions to affect the operation of the underlying projects or to alter our outlook for future production volumes.

B. Technologies Used in Establishing Proved Reserves Additions in 2016

Additions to ExxonMobil's proved reserves in 2016 were based on estimates generated through the integration of available and appropriate geological, engineering and production data, utilizing well-established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements including high-quality 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. Primary responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Commission (SEC) rules and regulations, review of annual changes in reserves estimates, and the reporting of ExxonMobil's proved reserves. This group also maintains the official company reserves estimates for ExxonMobil's proved reserves of crude and natural gas liquids, bitumen, synthetic oil and natural gas. In addition, the group provides training to personnel involved in the reserves estimation and reporting process within ExxonMobil and its affiliates. The Manager of the Global Reserves group has more than 25 years of experience in reservoir engineering and reserves assessment and has a degree in Engineering. He is an active member of the Society of Petroleum Engineers (SPE). The group is staffed with individuals that have an average of more than 20 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves under the SEC guidelines. This group includes individuals who hold advanced degrees in either Engineering or Geology. Several members of the group hold professional registrations in their field of expertise, and a member currently serves on the SPE Oil and Gas Reserves Committee.

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

2. Proved Undeveloped Reserves

At year-end 2016, approximately 6.2 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 31 percent of the 20 GOEB reported in proved reserves. This compares to the 6.8 GOEB of proved undeveloped reserves reported at the end of 2015. During the year, ExxonMobil conducted development activities in over 100 fields that resulted in the transfer of approximately 1 GOEB from proved undeveloped to proved developed reserves by year-end. The largest transfers were related to the Gorgon LNG project start-up and drilling activity at Upper Zakum, Tengiz and in the United States. During 2016, extensions, primarily in the United States, resulted in an addition of approximately 0.4 GOEB of proved undeveloped reserves.

Overall, investments of $10.1 billion were made by the Corporation during 2016 to progress the development of reported proved undeveloped reserves, including $9.3 billion for oil and gas producing activities and an additional $0.8 billion for other non-oil and gas producing activities such as the construction of support infrastructure and other related facilities. These investments represented 70 percent of the $14.5 billion in total reported Upstream capital and exploration expenditures. Investments made by the Corporation to develop quantities which no longer meet the SEC definition of proved reserves due to 2016 average prices are included in the $14.5 billion of Upstream capital expenditures reported above but are excluded from amounts related to progressing the development of proved undeveloped reserves.

One of ExxonMobil's requirements for reporting proved reserves is that management has made significant funding commitments toward the development of the reserves. ExxonMobil has a disciplined investment strategy and many major fields require long lead-time in order to be developed. Development projects typically take several years from the time of recording proved undeveloped reserves to the start of production. However, the development time for large and complex projects can exceed five years. Proved undeveloped reserves in Australia, the United States, Kazakhstan, the Netherlands, Qatar, and Nigeria have remained undeveloped for five years or more primarily due to constraints on the capacity of infrastructure, the pace of co-venturer/government funding, as well as the time required to complete development for very large projects. The Corporation is reasonably certain that these proved reserves will be produced; however, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals, and significant changes in long-term oil and natural gas price levels. Of the proved undeveloped reserves that have been reported for five or more years, over 80 percent are contained in the aforementioned countries. The largest of these is related to LNG/Gas projects in Australia, where construction of the Gorgon LNG project is in the final phases. In Kazakhstan, the proved undeveloped reserves are related to the remainder of the initial development of the offshore Kashagan field which is included in the North Caspian Production Sharing Agreement and the Tengizchevroil joint venture which includes a production license in the Tengiz – Korolev field complex. The Tengizchevroil joint venture is producing, and proved undeveloped reserves will continue to move to proved developed as approved development phases progress. In the Netherlands, the Groningen gas field has proved undeveloped reserves 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.

	2016		2015		2014	
	(thousands of barrels daily)					
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries						
United States	347	87	326	86	304	85
Canada/South America	53	6	47	8	52	9
Europe	171	31	173	28	151	28
Africa	459	15	511	18	469	20
Asia	383	27	346	29	293	26
Australia/Oceania	37	19	33	17	39	20
Total Consolidated Subsidiaries	1,450	185	1,436	186	1,308	188
Equity Companies						
United States	58	2	61	3	63	2
Europe	2	-	3	-	5	-
Asia	232	65	241	68	236	69
Total Equity Companies	292	67	305	71	304	71
Total crude oil and natural gas liquids production	1,742	252	1,741	257	1,612	259
Bitumen production						
Consolidated Subsidiaries						
Canada/South America	304		289		180	
Synthetic oil production						
Consolidated Subsidiaries						
Canada/South America	67		58		60	
Total liquids production	2,365		2,345		2,111	
	(millions of cubic feet daily)					
Natural gas production available for sale						
Consolidated Subsidiaries						
United States	3,052		3,116		3,374	
Canada/South America *(1)*	239		261		310	
Europe	1,093		1,110		1,226	
Africa	7		5		4	
Asia	927		1,080		1,067	
Australia/Oceania	887		677		512	
Total Consolidated Subsidiaries	6,205		6,249		6,493	
Equity Companies						
United States	26		31		30	
Europe	1,080		1,176		1,590	
Asia	2,816		3,059		3,032	
Total Equity Companies	3,922		4,266		4,652	
Total natural gas production available for sale	10,127		10,515		11,145	
	(thousands of oil-equivalent barrels daily)					
Oil-equivalent production	4,053		4,097		3,969	

(1) South America includes natural gas production available for sale for 2016, 2015 and 2014 of 22 million, 21 million, and 21 million cubic feet daily, respectively.

B. Production Prices and Production Costs

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

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
During 2016				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	36.47	39.50	40.57	42.59	41.89	43.33	40.59
NGL, per barrel	16.16	18.91	22.17	26.78	17.12	23.95	18.99
Natural gas, per thousand cubic feet	1.43	1.71	4.26	1.14	1.56	3.46	2.25
Bitumen, per barrel	-	19.30	-	-	-	-	19.30
Synthetic oil, per barrel	-	43.03	-	-	-	-	43.03
Average production costs, per oil-equivalent barrel - total	10.41	21.16	12.78	12.75	6.44	7.12	11.79
Average production costs, per barrel - bitumen	-	18.25	-	-	-	-	18.25
Average production costs, per barrel - synthetic oil	-	33.64	-	-	-	-	33.64
Equity Companies							
Average production prices							
Crude oil, per barrel	38.44	-	36.13	-	39.69	-	39.41
NGL, per barrel	14.85	-	-	-	25.21	-	24.87
Natural gas, per thousand cubic feet	2.03	-	4.19	-	3.59	-	3.75
Average production costs, per oil-equivalent barrel - total	22.26	-	7.92	-	1.80	-	4.21
Total							
Average production prices							
Crude oil, per barrel	36.75	39.50	40.51	42.59	41.06	43.33	40.39
NGL, per barrel	16.13	18.91	22.17	26.78	22.85	23.95	20.56
Natural gas, per thousand cubic feet	1.44	1.71	4.22	1.14	3.09	3.46	2.83
Bitumen, per barrel	-	19.30	-	-	-	-	19.30
Synthetic oil, per barrel	-	43.03	-	-	-	-	43.03
Average production costs, per oil-equivalent barrel - total	11.18	21.16	11.21	12.75	3.77	7.12	9.89
Average production costs, per barrel - bitumen	-	18.25	-	-	-	-	18.25
Average production costs, per barrel - synthetic oil	-	33.64	-	-	-	-	33.64
During 2015							
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	41.87	44.30	49.04	51.01	48.30	49.56	47.75
NGL, per barrel	16.96	21.91	27.50	33.41	21.14	29.75	22.16
Natural gas, per thousand cubic feet	1.65	1.78	6.47	1.57	2.02	5.13	2.95
Bitumen, per barrel	-	25.07	-	-	-	-	25.07
Synthetic oil, per barrel	-	48.15	-	-	-	-	48.15
Average production costs, per oil-equivalent barrel - total	12.50	22.68	15.86	10.31	7.71	8.86	12.97
Average production costs, per barrel - bitumen	-	19.20	-	-	-	-	19.20
Average production costs, per barrel - synthetic oil	-	41.83	-	-	-	-	41.83
Equity Companies							
Average production prices							
Crude oil, per barrel	46.34	-	46.05	-	48.44	-	47.99
NGL, per barrel	15.37	-	-	-	32.36	-	31.75
Natural gas, per thousand cubic feet	2.05	-	6.27	-	5.83	-	5.92
Average production costs, per oil-equivalent barrel - total	22.15	-	7.75	-	1.41	-	3.89
Total							
Average production prices							
Crude oil, per barrel	42.58	44.30	48.97	51.01	48.36	49.56	47.79
NGL, per barrel	16.92	21.91	27.50	33.41	28.94	29.75	24.77
Natural gas, per thousand cubic feet	1.65	1.78	6.37	1.57	4.84	5.13	4.16
Bitumen, per barrel	-	25.07	-	-	-	-	25.07
Synthetic oil, per barrel	-	48.15	-	-	-	-	48.15
Average production costs, per oil-equivalent barrel - total	13.16	22.68	13.09	10.31	3.96	8.86	10.56
Average production costs, per barrel - bitumen	-	19.20	-	-	-	-	19.20
Average production costs, per barrel - synthetic oil	-	41.83	-	-	-	-	41.83

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
During 2014				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	84.00	86.46	96.43	97.46	95.27	95.56	93.21
NGL, per barrel	39.70	51.86	53.68	65.21	40.81	56.77	47.07
Natural gas, per thousand cubic feet	3.61	3.96	8.18	2.61	3.71	5.87	4.68
Bitumen, per barrel	-	62.68	-	-	-	-	62.68
Synthetic oil, per barrel	-	89.76	-	-	-	-	89.76
Average production costs, per oil-equivalent barrel - total	13.35	33.03	22.29	12.58	8.64	11.05	15.94
Average production costs, per barrel - bitumen	-	32.66	-	-	-	-	32.66
Average production costs, per barrel - synthetic oil	-	55.32	-	-	-	-	55.32
Equity Companies							
Average production prices							
Crude oil, per barrel	91.24	-	88.68	-	93.42	-	92.89
NGL, per barrel	38.77	-	-	-	65.31	-	64.41
Natural gas, per thousand cubic feet	4.54	-	8.28	-	10.00	-	9.38
Average production costs, per oil-equivalent barrel - total	24.34	-	6.10	-	1.85	-	4.22
Total							
Average production prices							
Crude oil, per barrel	85.23	86.46	96.17	97.46	94.44	95.56	93.15
NGL, per barrel	39.68	51.86	53.68	65.21	58.52	56.77	51.84
Natural gas, per thousand cubic feet	3.62	3.96	8.23	2.61	8.36	5.87	6.64
Bitumen, per barrel	-	62.68	-	-	-	-	62.68
Synthetic oil, per barrel	-	89.76	-	-	-	-	89.76
Average production costs, per oil-equivalent barrel - total	14.10	33.03	15.59	12.58	4.44	11.05	12.55
Average production costs, per barrel - bitumen	-	32.66	-	-	-	-	32.66
Average production costs, per barrel - synthetic oil	-	55.32	-	-	-	-	55.32

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

4. Drilling and Other Exploratory and Development Activities

A. Number of Net Productive and Dry Wells Drilled

	2016	2015	2014
Net Productive Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	-	-	3
Canada/South America	2	1	3
Europe	1	1	1
Africa	1	1	2
Asia	-	2	-
Australia/Oceania	-	1	-
Total Consolidated Subsidiaries	4	6	9
Equity Companies			
United States	-	-	-
Europe	1	1	2
Asia	-	-	-
Total Equity Companies	1	1	2
Total productive exploratory wells drilled	5	7	11
Net Dry Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	-	1	2
Canada/South America	1	-	1
Europe	-	2	1
Africa	1	-	1
Asia	-	-	-
Australia/Oceania	-	-	-
Total Consolidated Subsidiaries	2	3	5
Equity Companies			
United States	-	1	2
Europe	-	1	-
Asia	-	-	-
Total Equity Companies	-	2	2
Total dry exploratory wells drilled	2	5	7

	2016	2015	2014
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
United States	335	692	721
Canada/South America	13	53	178
Europe	9	10	8
Africa	7	23	41
Asia	13	14	19
Australia/Oceania	-	4	5
Total Consolidated Subsidiaries	377	796	972
Equity Companies			
United States	121	390	340
Europe	2	1	2
Asia	3	2	1
Total Equity Companies	126	393	343
Total productive development wells drilled	503	1,189	1,315
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	2	5	6
Canada/South America	-	-	3
Europe	2	3	1
Africa	-	1	-
Asia	-	-	-
Australia/Oceania	-	-	-
Total Consolidated Subsidiaries	4	9	10
Equity Companies			
United States	-	-	-
Europe	-	-	1
Asia	-	-	-
Total Equity Companies	-	-	1
Total dry development wells drilled	4	9	11
Total number of net wells drilled	514	1,210	1,344

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

Syncrude Operations. Syncrude is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen, and then upgrade it to produce a high-quality, light (32 degrees API), sweet, synthetic crude oil. Imperial Oil Limited is the owner of a 25 percent interest in the joint venture. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited. In 2016, the company's share of net production of synthetic crude oil was about 67 thousand barrels per day and share of net acreage was about 63 thousand acres in the Athabasca oil sands deposit.

Kearl Operations. Kearl is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen. Imperial Oil Limited holds a 70.96 percent interest in the joint venture and ExxonMobil Canada Properties holds the other 29.04 percent. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited and a 100 percent interest in ExxonMobil Canada Properties. Kearl is comprised of six oil sands leases covering about 49 thousand acres in the Athabasca oil sands deposit.

Kearl is located approximately 40 miles north of Fort McMurray, Alberta, Canada. Bitumen is extracted from oil sands produced from open-pit mining operations, and processed through bitumen extraction and froth treatment trains. 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 and rail. During 2016, average net production at Kearl was about 167 thousand barrels per day.

As a result of very low prices during 2016, under the SEC definition of proved reserves, the entire 3.5 billion barrels of bitumen at Kearl did not qualify as proved reserves at year-end 2016. Among the factors that would result in these amounts being recognized again as proved reserves at some point in the future are a recovery in average price levels, a further decline in costs, and / or operating efficiencies.

5. Present Activities

A. Wells Drilling

	Year-End 2016		Year-End 2015	
	Gross	Net	Gross	Net
Wells Drilling				
Consolidated Subsidiaries				
United States	760	302	860	379
Canada/South America	22	17	21	16
Europe	12	3	14	6
Africa	30	7	23	7
Asia	38	11	65	18
Australia/Oceania	4	1	3	1
Total Consolidated Subsidiaries	866	341	986	427
Equity Companies				
United States	22	3	18	3
Europe	9	4	9	3
Asia	7	2	1	-
Total Equity Companies	38	9	28	6
Total gross and net wells drilling	904	350	1,014	433

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2016 acreage holdings totaled 12.9 million net acres, of which 1.0 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska.

During the year, 442.3 net 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 and the Bakken oil play in North Dakota. In addition, gas development activities continued in the Marcellus Shale of Pennsylvania and West Virginia, the Utica Shale of Ohio and the Haynesville Shale of East Texas and Louisiana.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2016 was 0.9 million acres. A total of 1.6 net exploration and development wells were completed during the year. The deepwater Julia project and the non-operated Heidelberg project started up in 2016.

Participation in Alaska production and development continued with a total of 14.0 net development wells completed. The Point Thomson Initial Production System started up in 2016.

CANADA / SOUTH AMERICA

Canada

Oil and Gas Operations: ExxonMobil's year-end 2016 acreage holdings totaled 6.5 million net acres, of which 3.2 million net acres were offshore. A total of 11.5 net development wells were completed during the year. Development activities continued on the Hebron project during 2016. ExxonMobil acquired deepwater acreage offshore Eastern Canada in 2016.

In Situ Bitumen Operations: ExxonMobil's year-end 2016 in situ bitumen acreage holdings totaled 0.7 million net onshore acres.

Argentina

ExxonMobil's net acreage totaled 0.3 million onshore acres at year-end 2016, and there were 3.4 net exploration and development wells completed during the year.

EUROPE

Germany

A total of 3.1 million net onshore acres were held by ExxonMobil at year-end 2016, with 0.6 net exploration and development wells completed in the year.

Netherlands

ExxonMobil's net interest in licenses totaled approximately 1.5 million acres at year-end 2016, of which 1.1 million acres were onshore. A total of 2.9 net exploration and development wells were completed during the year.

Norway

ExxonMobil's net interest in licenses at year-end 2016 totaled approximately 0.2 million acres, all offshore. A total of 8.9 net exploration and development wells were completed in 2016.

United Kingdom

ExxonMobil's net interest in licenses at year-end 2016 totaled approximately 0.4 million acres, all offshore. A total of 1.8 net exploration and development wells were completed during the year.

AFRICA

Angola

ExxonMobil's net acreage totaled 0.4 million offshore acres at year-end 2016, with 4.8 net development wells completed during the year. On Block 32, development activities continued on the Kaombo Split Hub project.

Chad

ExxonMobil's net year-end 2016 acreage holdings consisted of 46 thousand onshore acres.

Equatorial Guinea

ExxonMobil's acreage totaled 0.3 million net offshore acres at year-end 2016.

Nigeria

ExxonMobil's net acreage totaled 1.1 million offshore acres at year-end 2016, with 3.1 net exploration and development wells completed during the year. Development drilling was completed on the deepwater Erha North Phase 2 and Usan projects in 2016.

ASIA

Azerbaijan

At year-end 2016, ExxonMobil's net acreage totaled 9 thousand offshore acres. A total of 1.4 net development wells were completed during the year.

Indonesia

At year-end 2016, ExxonMobil had 0.5 million net acres, 0.4 million net acres offshore and 0.1 million net acres onshore.

Iraq

At year-end 2016, ExxonMobil's onshore acreage was 0.2 million net acres. A total of 3.1 net development wells were completed at the West Qurna Phase I oil field during the year. Oil field rehabilitation activities continued during 2016 and across the life of this project will include drilling of new wells, working over of existing wells, and optimization and debottlenecking of existing facilities. In the Kurdistan Region of Iraq, ExxonMobil completed seismic operations on one block and continued exploration activities.

Kazakhstan

ExxonMobil's net acreage totaled 0.1 million acres onshore and 0.2 million acres offshore at year-end 2016. A total of 5.3 net development wells were completed during 2016. Following a brief production period in 2013, Kashagan operations were suspended due to a leak discovered in the onshore section of the gas pipeline. Working with our partners, both the oil and gas pipelines were replaced and production commenced in October 2016. The Tengiz Expansion project was funded in 2016.

Malaysia

ExxonMobil has interests in production sharing contracts covering 0.2 million net acres offshore at year-end 2016.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil's net acreage totaled 65 thousand acres offshore at year-end 2016. ExxonMobil participated in 62.2 million tonnes per year gross liquefied natural gas capacity and 2.0 billion cubic feet per day of flowing gas capacity at year end. Construction and commissioning activities on the Barzan project progressed in 2016.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 10 thousand acres onshore at year-end 2016.

Russia

ExxonMobil's net acreage holdings in Sakhalin at year-end 2016 were 85 thousand acres, all offshore. A total of 1.8 net development wells were completed. Development activities continued on the Odoptu Stage 2 project in 2016.

At year-end 2016, ExxonMobil's net acreage in the Rosneft joint venture agreements for the Kara, Laptev, Chukchi and Black Seas was 63.6 million acres, all offshore. 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 2016.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2016. During the year, a total of 4.5 net development wells were completed. Development activities continued on the Upper Zakum 750 project.

AUSTRALIA / OCEANIA

Australia

ExxonMobil's year-end 2016 acreage holdings totaled 1.5 million net offshore acres. Construction and commissioning activities continued during 2016 on the Gas Conditioning Plant at Longford.

The first two trains and the domestic gas plant of the co-venturer-operated Gorgon Jansz liquefied natural gas (LNG) project started up in 2016, and construction activities continued on the third train. 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 cubic feet per day domestic gas plant located on Barrow Island, Western Australia.

Papua New Guinea

A total of 5.0 million net acres were held by ExxonMobil at year-end 2016, of which 4.1 million net acres were offshore. The Papua New Guinea (PNG) LNG integrated development includes gas production and processing facilities in the southern PNG Highlands, onshore and offshore pipelines, and a 6.9 million tonnes per year LNG facility near Port Moresby. ExxonMobil acquired deepwater acreage offshore Papua New Guinea during 2016.

WORLDWIDE EXPLORATION

At year-end 2016, exploration activities were under way in several areas in which ExxonMobil has no established production operations and thus are not included above. A total of 10.0 million net acres were held at year-end 2016 and 3.1 net exploration wells were completed during the year in these countries.

6. Delivery Commitments

ExxonMobil sells crude oil and natural gas from its producing operations under a variety of contractual obligations, some of which may specify the delivery of a fixed and determinable quantity for periods longer than one year. ExxonMobil also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be a combination of our own production and the spot market. Worldwide, we are contractually committed to deliver approximately 94 million barrels of oil and 2,500 billion cubic feet of natural gas for the period from 2017 through 2019. We expect to fulfill the majority of these delivery commitments with production from our proved developed reserves. Any remaining commitments will be fulfilled with production from our proved undeveloped reserves and spot market purchases as necessary.

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

A. Gross and Net Productive Wells

	Year-End 2016				Year-End 2015			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	20,470	8,037	32,949	19,873	20,662	8,334	33,657	20,307
Canada/South America	5,024	4,767	4,362	1,668	5,045	4,741	4,559	1,769
Europe	1,130	323	641	253	1,195	345	644	255
Africa	1,268	494	17	7	1,315	517	20	8
Asia	882	299	140	82	818	280	149	87
Australia/Oceania	588	128	53	23	630	138	49	23
Total Consolidated Subsidiaries	29,362	14,048	38,162	21,906	29,665	14,355	39,078	22,449
Equity Companies								
United States	13,957	5,315	4,257	491	14,555	5,594	4,301	493
Europe	56	19	586	186	13	6	570	180
Asia	131	33	125	30	121	30	125	30
Total Equity Companies	14,144	5,367	4,968	707	14,689	5,630	4,996	703
Total gross and net productive wells	43,506	19,415	43,130	22,613	44,354	19,985	44,074	23,152

There were 35,047 gross and 29,375 net operated wells at year-end 2016 and 35,909 gross and 30,114 net operated wells at year-end 2015. The number of wells with multiple completions was 1,209 gross in 2016 and 1,266 gross in 2015.

B. Gross and Net Developed Acreage

	Year-End 2016		Year-End 2015	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	14,678	8,958	14,827	9,327
Canada/South America *(1)*	3,374	2,146	3,335	2,122
Europe	3,215	1,446	3,275	1,473
Africa	2,492	866	2,493	866
Asia	1,934	562	1,934	562
Australia/Oceania	3,020	1,005	2,123	781
Total Consolidated Subsidiaries	28,713	14,983	27,987	15,131
Equity Companies				
United States	929	209	939	209
Europe	4,191	1,321	4,278	1,335
Asia	628	155	628	155
Total Equity Companies	5,748	1,685	5,845	1,699
Total gross and net developed acreage	34,461	16,668	33,832	16,830

(1) Includes developed acreage in South America of 213 gross and 109 net thousands of acres for both 2015 and 2016.

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 2016		Year-End 2015	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	7,854	3,637	9,353	4,358
Canada/South America *(1)*	24,054	10,569	19,328	10,113
Europe	7,218	3,368	10,073	5,444
Africa	9,496	4,979	10,586	5,306
Asia	2,436	865	6,888	3,959
Australia/Oceania	8,054	5,497	5,629	1,902
Total Consolidated Subsidiaries	59,112	28,915	61,857	31,082
Equity Companies				
United States	223	81	259	92
Europe	100	25	-	-
Asia	191,147	63,633	191,147	63,633
Total Equity Companies	191,470	63,739	191,406	63,725
Total gross and net undeveloped acreage	250,582	92,654	253,263	94,807

(1) Includes undeveloped acreage in South America of 13,106 gross and 5,146 net thousands of acres for 2016 and 10,634 gross and 4,970 net thousands of acres for 2015.

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

D. Summary of Acreage Terms

UNITED STATES

Oil and gas exploration and production rights are acquired from mineral interest owners through a lease. Mineral interest owners include the Federal and State governments, as well as private mineral interest owners. Leases typically 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 regarding private property, a "fee interest" is acquired where the underlying mineral interests are owned outright.

CANADA / SOUTH AMERICA

Canada

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

Argentina

The Federal 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 each. Extensions are subject to specific, minimum work commitments. Production licenses are normally granted for 20 to 25 years with multiple possible extensions as long as there is production on the license.

Netherlands

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

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

Norway

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

United Kingdom

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

AFRICA

Angola

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

Chad

Exploration permits are issued for a period of five years, and are renewable for one or two further five-year periods. The terms and conditions of the permits, including relinquishment obligations, are specified in a negotiated convention. The production term is for 30 years and may be extended up to 50 years at the discretion of the government.

Equatorial Guinea

Exploration, development and production activities are governed by production sharing contracts (PSCs) negotiated with the State Ministry of Mines and Hydrocarbons. A new PSC was signed in 2015; the initial exploration period is five years for oil and gas, with multi-year extensions available at the discretion of the Ministry and limited relinquishments in the absence of commercial discoveries. The production period for crude oil ranges from 25 to 30 years, while the production period for natural gas ranges from 25 to 50 years.

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 typically holds the underlying Oil Prospecting License (OPL) and any resulting Oil Mining Lease (OML). The terms of the PSCs are generally 30 years, including a ten-year exploration period (an initial exploration phase that can be divided into multiple optional periods) covered by an OPL. Upon commercial discovery, an OPL may be converted to an OML. Partial relinquishment is required under the PSC at the end of the ten-year exploration period, and OMLs have a 20-year production period that may be extended.

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

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

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

ASIA

Azerbaijan

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

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

Indonesia

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

Iraq

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

Exploration and production activities in the Kurdistan Region of Iraq are governed by production sharing contracts (PSCs) negotiated with the regional government of Kurdistan in 2011. The exploration term is for five years, with extensions available as provided by the PSCs and at the discretion of the regional government of Kurdistan. Current PSCs remain in effect by agreement of the regional government to allow additional time for exploration or evaluation of commerciality. The production period is 20 years with the right to extend for five years.

Kazakhstan

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

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

Malaysia

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

Qatar

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

Republic of Yemen

The Jannah production sharing agreement has a development period extending 20 years from first commercial declaration, which was made in June 1995. Due to force majeure events, the development period has been extended beyond its original expiration date by an additional 735 days, with the possibility of further extensions due to ongoing force majeure events.

Russia

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

Exploration and production activities in the Kara, Laptev, Chukchi and Black Seas are governed by joint venture agreements concluded with 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 prevalent at the time.

United Arab Emirates

An interest in the development and production activities of the Upper Zakum field, a major offshore field, was acquired effective as of January 2006, for a term expiring March 2026, and in 2013 the governing agreements were extended to 2041.

AUSTRALIA / OCEANIA

Australia

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

Papua New Guinea

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

Information with regard to the Downstream segment follows:

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

Refining Capacity At Year-End 2016 *(1)*

		ExxonMobil Share KBD *(2)*	ExxonMobil Interest %
United States			
Joliet	Illinois	236	100
Baton Rouge	Louisiana	503	100
Billings	Montana	60	100
Baytown	Texas	561	100
Beaumont	Texas	363	100
Total United States		1,723	
Canada			
Strathcona	Alberta	191	69.6
Nanticoke	Ontario	113	69.6
Sarnia	Ontario	119	69.6
Total Canada		423	
Europe			
Antwerp	Belgium	307	100
Fos-sur-Mer	France	133	82.9
Gravenchon	France	239	82.9
Karlsruhe	Germany	78	25
Augusta	Italy	198	100
Trecate	Italy	132	74.8
Rotterdam	Netherlands	191	100
Slagen	Norway	116	100
Fawley	United Kingdom	261	100
Total Europe		1,655	
Asia Pacific			
Altona	Australia	80	100
Fujian	China	67	25
Jurong/PAC	Singapore	592	100
Sriracha	Thailand	167	66
Total Asia Pacific		906	
Middle East			
Yanbu	Saudi Arabia	200	50
Total Worldwide		4,907	

(1) Capacity data is based on 100 percent of rated refinery process unit stream-day capacities under normal operating conditions, less the impact of shutdowns for regular repair and maintenance activities, averaged over an extended period of time. The listing excludes cost company refining capacity in New Zealand, and the Laffan Refinery in Qatar for which results are reported in the Upstream segment.

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

The marketing operations sell products and services throughout the world through our *Exxon*, *Esso* and *Mobil* brands.

Retail Sites At Year-End 2016

United States	
Owned/leased	-
Distributors/resellers	10,196
Total United States	10,196
Canada	
Owned/leased	-
Distributors/resellers	1,792
Total Canada	1,792
Europe	
Owned/leased	2,243
Distributors/resellers	3,649
Total Europe	5,892
Asia Pacific	
Owned/leased	617
Distributors/resellers	855
Total Asia Pacific	1,472
Latin America	
Owned/leased	5
Distributors/resellers	771
Total Latin America	776
Middle East/Africa	
Owned/leased	349
Distributors/resellers	306
Total Middle East/Africa	655
Worldwide	
Owned/leased	3,214
Distributors/resellers	17,569
Total Worldwide	20,783

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 2016 *(1)(2)*

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

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

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

ITEM 3. LEGAL PROCEEDINGS

On December 8, 2016, the Texas Commission on Environmental Quality (TCEQ) contacted the Corporation concerning alleged violations of the Texas Clean Air Act, certain implementing regulations, and the applicable new source review permit in connection with exceedances of the nitrogen oxide emission limit at a compressor engine and volatile organic compound emission limits at Tanks 21 and 23 at the Corporation's former King Ranch Gas Plant. The TCEQ is seeking a civil penalty in excess of $100,000, and the Corporation is working with the TCEQ to resolve the matter.

As reported in the Corporation's Form 10-Q for the second and third quarters of 2014, on May 20, 2014, the TCEQ issued a Notice of Enforcement and Proposed Agreed Order (the Agreed Order) alleging that record reviews and inspections at ExxonMobil Oil Corporation's (EMOC) Beaumont, Texas, refinery in 2013 and 2014, identified deficiencies in the refinery's cooling tower monitoring activities and one air emission event, which allegedly violated provisions of the Texas Health and Safety Code, the Texas Water Code, and the Code of Federal Regulations. Additionally, the TCEQ identified deficiencies in a refinery continuous emissions monitoring system relative accuracy test audit procedure. On November 8, 2016, the TCEQ formally approved and signed the Agreed Order. EMOC previously paid the agreed $100,430 fine to the TCEQ, and on November 28, 2016, EMOC made a $100,429 payment for the benefit of the Southeast Texas Regional Planning Commission for the Meteorological and Air Monitoring Network Project, thereby satisfying all remaining financial obligations under the Agreed Order and concluding this matter.

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)]

Darren W. Woods — *Chairman of the Board*

Held current title since: January 1, 2017 — Age: 52

Mr. Darren W. Woods was Vice President, Supply & Transportation, ExxonMobil Refining & Supply Company July 1, 2010 – July 31, 2012. He was President of ExxonMobil Refining & Supply Company August 1, 2012 – July 31, 2014 and Vice President of Exxon Mobil Corporation August 1, 2012 – May 31, 2014. He was Senior Vice President of Exxon Mobil Corporation June 1, 2014 – December 31, 2015. He became a Director and President of Exxon Mobil Corporation on January 1, 2016, and Chairman of the Board and Chief Executive Officer on January 1, 2017, positions he still holds as of this filing date.

Mark W. Albers — *Senior Vice President*

Held current title since: April 1, 2007 — Age: 60

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

Michael J. Dolan — *Senior Vice President*

Held current title since: April 1, 2008 — Age: 63

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

Andrew P. Swiger — *Senior Vice President*

Held current title since: April 1, 2009 — Age: 60

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

Jack P. Williams, Jr. — *Senior Vice President*

Held current title since: June 1, 2014 — Age: 53

Mr. Jack P. Williams, Jr. was President of XTO 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.

Neil A. Chapman — *Vice President*

Held current title since: January 1, 2015 — Age: 54

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

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

Held current title since: February 1, 2009 — Age: 63

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.

Bradley W. Corson	*Vice President*	
Held current title since:	March 1, 2015	Age: 55

Mr. Bradley W. Corson was Regional Vice President, Europe/Caspian for ExxonMobil Production Company May 1, 2009 – April 30, 2014. He was Vice President, ExxonMobil Upstream Ventures May 1, 2014 – February 28, 2015. He became President of ExxonMobil Upstream Ventures and Vice President of Exxon Mobil Corporation on March 1, 2015, positions he still holds as of this filing date.

Neil W. Duffin	*Vice President*	
Held current title since:	January 1, 2017	Age: 60

Mr. Neil W. Duffin was President of ExxonMobil Development Company April 13, 2007 – December 31, 2016. He became President of ExxonMobil Production Company and Vice President of Exxon Mobil Corporation on January 1, 2017, positions he still holds as of this filing date.

Randall M. Ebner	*Vice President and General Counsel*	
Held current title since:	November 1, 2016	Age: 61

Mr. Randall M. Ebner was Assistant General Counsel of Exxon Mobil Corporation January 1, 2009 – October 31, 2016. He became Vice President and General Counsel of Exxon Mobil Corporation on November 1, 2016, positions he still holds as of this filing date.

Robert S. Franklin	*Vice President*	
Held current title since:	May 1, 2009	Age: 59

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: 59

Mr. Stephen M. Greenlee 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.

Liam M. Mallon	*President, ExxonMobil Development Company*	
Held current title since:	January 1, 2017	Age: 54

Mr. Liam M. Mallon was Vice President, Engineering, ExxonMobil Production Company May 1, 2009 – May 31, 2012. He was Vice President, Africa, ExxonMobil Production Company June 1, 2012 – January 31, 2014. He was Executive Vice President, ExxonMobil Development Company February 1, 2014 – December 31, 2016. He became President of ExxonMobil Development Company on January 1, 2017, a position he still holds as of this filing date.

Bryan W. Milton	*Vice President*	
Held current title since:	August 1, 2016	Age: 52

Mr. Bryan W. Milton was President of ExxonMobil Global Services Company April 1, 2011 – July 31, 2016. He became President of ExxonMobil Fuels, Lubricants & Specialties Marketing Company and Vice President of Exxon Mobil Corporation on August 1, 2016, positions he still holds as of this filing date.

Sara N. Ortwein	*President, XTO Energy Inc., a subsidiary of the Corporation*	
Held current title since:	November 1, 2016	Age: 58

Ms. Sara N. Ortwein was President of ExxonMobil Upstream Research Company September 1, 2010 – October 31, 2016. She became President of XTO Energy Inc. on November 1, 2016, a position she still holds as of this filing date.

David S. Rosenthal	*Vice President and Controller*	
Held current title since:	October 1, 2008 (Vice President) September 1, 2014 (Controller)	Age: 60

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

Robert N. Schleckser	*Vice President and Treasurer*	
Held current title since:	May 1, 2011	Age: 60

Mr. Robert N. Schleckser became Vice President and Treasurer of Exxon Mobil Corporation on May 1, 2011, positions he still holds as of this filing date.

James M. Spellings, Jr.	*Vice President and General Tax Counsel*	
Held current title since:	March 1, 2010	Age: 55

Mr. James M. Spellings, Jr. became Vice President and General Tax Counsel of Exxon Mobil Corporation on March 1, 2010, positions he still holds as of this filing date.

Dennis G. Wascom	*Vice President*	
Held current title since:	August 1, 2014	Age: 60

Mr. Dennis G. Wascom was Director, Refining Americas, ExxonMobil Refining & Supply Company April 1, 2009 – June 30, 2013. He was Director, Refining North America, ExxonMobil Refining & Supply Company July 1, 2013 – July 31, 2014. He became President of ExxonMobil 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	*Vice President – Investor Relations and Secretary*	
Held current title since:	July 1, 2011 (Vice President) September 1, 2014 (Secretary)	Age: 56

Mr. Jeffrey J. Woodbury was 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 officer serving until a successor has been elected and qualified.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Reference is made to the "Quarterly Information" portion of the Financial Section of this report.

Recent Sales of Unregistered Securities

As previously reported in the Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2016, on July 21, 2016, the Corporation entered into an Arrangement Agreement, as amended and restated on December 15, 2016, to acquire all of the issued and outstanding common stock of InterOil Corporation (IOC) in exchange for consideration including around 28 million shares of Exxon Mobil Corporation common stock. With respect to the shares of common stock to be issued in connection with the transaction, the Corporation is relying on the exemption from registration provided by Section 3(a)(10) of the Securities Act of 1933.

As previously reported in the Corporation's Current Report on Form 8-K filed January 17, 2017, on January 16, 2017, an affiliate of the Corporation entered into a Purchase and Sale Agreement (PSA) to acquire companies owned by the Bass family of Fort Worth, Texas, that indirectly own certain oil and gas properties in the Permian Basin and certain additional properties and related assets in exchange for issuance to the sellers of shares of Exxon Mobil Corporation common stock having an aggregate value at the time of closing of $5.6 billion. The number of shares of the Corporation's common stock for this purpose will be determined based on the Corporation's volume-weighted average trading price over a 10-day period ending on the third trading date immediately preceding the closing date. The transaction is currently expected to close on or about February 28, 2017. As of January 16, 2017, the number of shares issuable in connection with the transaction would have been approximately 63 million. The sale of shares under the PSA has been structured as a private placement solely to accredited investors and therefore the Corporation is relying on the exemption from registration provided by Section 4(a)(2) of the Securities Act of 1933.

See "Note 20: Subsequent Events" of the Financial Section of this report for additional information regarding these transactions.

Issuer Purchases of Equity Securities for Quarter Ended December 31, 2016

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 2016	-		-	
November 2016	-		-	
December 2016	-		-	
Total	-		-	(See Note 1)

During the fourth quarter, the Corporation did not purchase any shares of its common stock for the treasury.

Note 1 - On August 1, 2000, the Corporation announced its intention to resume purchases of shares of its common stock for the treasury both to offset shares issued in conjunction with company benefit plans and programs and to gradually reduce the number of shares outstanding. The announcement did not specify an amount or expiration date. The Corporation has continued to purchase shares since this announcement and to report purchased volumes in its quarterly earnings releases. In its earnings release dated February 2, 2016, the Corporation stated it will continue to acquire shares to offset dilution in conjunction with benefit plans and programs, but had suspended making purchases to reduce shares outstanding effective beginning the first quarter of 2016.

ITEM 6. SELECTED FINANCIAL DATA

	Years Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	218,608	259,488	394,105	420,836	451,509
(1) Sales-based taxes included	*21,090*	*22,678*	*29,342*	*30,589*	*32,409*
Net income attributable to ExxonMobil	7,840	16,150	32,520	32,580	44,880
Earnings per common share	1.88	3.85	7.60	7.37	9.70
Earnings per common share - assuming dilution	1.88	3.85	7.60	7.37	9.70
Cash dividends per common share	2.98	2.88	2.70	2.46	2.18
Total assets	330,314	336,758	349,493	346,808	333,795
Long-term debt	28,932	19,925	11,653	6,891	7,928

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

- Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP dated February 22, 2017, beginning with the section entitled "Report of Independent Registered Public Accounting Firm" and continuing through "Note 20: Subsequent Events";
- "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, 2016. Based on that evaluation, these officers have concluded that the Corporation's disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Corporation in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

Management's Report on Internal Control Over Financial Reporting

Management, including the Corporation's Chief Executive Officer, Principal Financial Officer and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2016.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2016, 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 2017 annual meeting of shareholders (the "2017 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 2017 Proxy Statement.

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

The information required under Item 403 of Regulation S-K is incorporated by reference to the sections "Director and Executive Officer Stock Ownership" and "Certain Beneficial Owners" of the registrant's 2017 Proxy Statement.

Equity Compensation Plan Information

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	35,145,445 *(1)*	-	93,606,538 *(2)(3)*
Equity compensation plans not approved by security holders	-	-	-
Total	35,145,445	-	93,606,538

(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 93,066,338 shares available for award under the 2003 Incentive Program and 540,200 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 and, if the director remains in office, an additional 2,500 restricted shares each following year. While on the Board, each non-employee director receives the same cash dividends on restricted shares as a holder of regular common stock, but the director is not allowed to sell the shares. The restricted shares may be forfeited if the director leaves the Board early.

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

Incorporated by reference to the portions entitled "Related Person Transactions and Procedures" and "Director Independence" of the section entitled "Corporate Governance" of the registrant's 2017 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Incorporated by reference to the portion entitled "Audit Committee" of the section entitled "Corporate Governance" and the section entitled "Ratification of Independent Auditors" of the registrant's 2017 Proxy Statement.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

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

FINANCIAL SECTION

TABLE OF CONTENTS

BUSINESS PROFILE

Financial	Earnings After Income Taxes 2016	Earnings After Income Taxes 2015	Average Capital Employed 2016	Average Capital Employed 2015	Return on Average Capital Employed 2016	Return on Average Capital Employed 2015	Capital and Exploration Expenditures 2016	Capital and Exploration Expenditures 2015
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	(4,151)	(1,079)	62,114	64,086	(6.7)	(1.7)	3,518	7,822
Non-U.S.	4,347	8,180	107,941	105,868	4.0	7.7	11,024	17,585
Total	196	7,101	170,055	169,954	0.1	4.2	14,542	25,407
Downstream								
United States	1,094	1,901	7,573	7,497	14.4	25.4	839	1,039
Non-U.S.	3,107	4,656	14,231	15,756	21.8	29.6	1,623	1,574
Total	4,201	6,557	21,804	23,253	19.3	28.2	2,462	2,613
Chemical								
United States	1,876	2,386	9,018	7,696	20.8	31.0	1,553	1,945
Non-U.S.	2,739	2,032	15,826	16,054	17.3	12.7	654	898
Total	4,615	4,418	24,844	23,750	18.6	18.6	2,207	2,843
Corporate and financing	(1,172)	(1,926)	(4,477)	(8,202)	-	-	93	188
Total	7,840	16,150	212,226	208,755	3.9	7.9	19,304	31,051

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

Operating	2016	2015		2016	2015
	(thousands of barrels daily)			*(thousands of barrels daily)*	
Net liquids production			Refinery throughput		
United States	494	476	United States	1,591	1,709
Non-U.S.	1,871	1,869	Non-U.S.	2,678	2,723
Total	2,365	2,345	Total	4,269	4,432
	(millions of cubic feet daily)			*(thousands of barrels daily)*	
Natural gas production available for sale			Petroleum product sales *(2)*		
United States	3,078	3,147	United States	2,250	2,521
Non-U.S.	7,049	7,368	Non-U.S.	3,232	3,233
Total	10,127	10,515	Total	5,482	5,754
	(thousands of oil-equivalent barrels daily)			*(thousands of metric tons)*	
Oil-equivalent production *(1)*	4,053	4,097	Chemical prime product sales *(2)(3)*		
			United States	9,576	9,664
			Non-U.S.	15,349	15,049
			Total	24,925	24,713

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

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

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

FINANCIAL INFORMATION

	2016	2015	2014	2013	2012
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	218,608	259,488	394,105	420,836	451,509
Earnings					
Upstream	196	7,101	27,548	26,841	29,895
Downstream	4,201	6,557	3,045	3,449	13,190
Chemical	4,615	4,418	4,315	3,828	3,898
Corporate and financing	(1,172)	(1,926)	(2,388)	(1,538)	(2,103)
Net income attributable to ExxonMobil	7,840	16,150	32,520	32,580	44,880
Earnings per common share	1.88	3.85	7.60	7.37	9.70
Earnings per common share – assuming dilution	1.88	3.85	7.60	7.37	9.70
Cash dividends per common share	2.98	2.88	2.70	2.46	2.18
Earnings to average ExxonMobil share of equity (percent)	4.6	9.4	18.7	19.2	28.0
Working capital	(6,222)	(11,353)	(11,723)	(12,416)	321
Ratio of current assets to current liabilities (times)	0.87	0.79	0.82	0.83	1.01
Additions to property, plant and equipment	16,100	27,475	34,256	37,741	35,179
Property, plant and equipment, less allowances	244,224	251,605	252,668	243,650	226,949
Total assets	330,314	336,758	349,493	346,808	333,795
Exploration expenses, including dry holes	1,467	1,523	1,669	1,976	1,840
Research and development costs	1,058	1,008	971	1,044	1,042
Long-term debt	28,932	19,925	11,653	6,891	7,928
Total debt	42,762	38,687	29,121	22,699	11,581
Fixed-charge coverage ratio (times)	5.7	17.6	46.9	55.7	62.4
Debt to capital (percent)	19.7	18.0	13.9	11.2	6.3
Net debt to capital (percent) *(2)*	18.4	16.5	11.9	9.1	1.2
ExxonMobil share of equity at year-end	167,325	170,811	174,399	174,003	165,863
ExxonMobil share of equity per common share	40.34	41.10	41.51	40.14	36.84
Weighted average number of common shares outstanding (millions)	4,177	4,196	4,282	4,419	4,628
Number of regular employees at year-end (thousands) *(3)*	71.1	73.5	75.3	75.0	76.9
CORS employees not included above (thousands) *(4)*	1.6	2.1	8.4	9.8	11.1

(1) Sales and other operating revenue includes sales-based taxes of $21,090 million for 2016, $22,678 million for 2015, $29,342 million for 2014, $30,589 million for 2013 and $32,409 million for 2012.

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

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

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

FREQUENTLY USED TERMS

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

Cash Flow From Operations and Asset Sales

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

Cash flow from operations and asset sales	2016	2015	2014
		(millions of dollars)	
Net cash provided by operating activities	22,082	30,344	45,116
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	4,275	2,389	4,035
Cash flow from operations and asset sales	26,357	32,733	49,151

Capital Employed

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

Capital employed	2016	2015	2014
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	330,314	336,758	349,493
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(33,808)	(35,214)	(47,165)
Total long-term liabilities excluding long-term debt	(79,914)	(86,047)	(92,143)
Noncontrolling interests share of assets and liabilities	(8,031)	(8,286)	(9,099)
Add ExxonMobil share of debt-financed equity company net assets	4,233	4,447	4,766
Total capital employed	212,794	211,658	205,852
Total corporate sources: debt and equity perspective			
Notes and loans payable	13,830	18,762	17,468
Long-term debt	28,932	19,925	11,653
ExxonMobil share of equity	167,325	170,811	174,399
Less noncontrolling interests share of total debt	(1,526)	(2,287)	(2,434)
Add ExxonMobil share of equity company debt	4,233	4,447	4,766
Total capital employed	212,794	211,658	205,852

FREQUENTLY USED TERMS

Return on Average Capital Employed

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

Return on average capital employed	**2016**	**2015**	**2014**
		(millions of dollars)	
Net income attributable to ExxonMobil	7,840	16,150	32,520
Financing costs (after tax)			
Gross third-party debt	(683)	(362)	(140)
ExxonMobil share of equity companies	(225)	(170)	(256)
All other financing costs – net	423	88	(68)
Total financing costs	(485)	(444)	(464)
Earnings excluding financing costs	8,325	16,594	32,984
Average capital employed	212,226	208,755	203,110
Return on average capital employed – corporate total	3.9%	7.9%	16.2%

QUARTERLY INFORMATION

	2016					2015				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Volumes										
Production of crude oil,					*(thousands of barrels daily)*					
natural gas liquids, synthetic oil and bitumen	2,538	2,330	2,211	2,384	2,365	2,277	2,291	2,331	2,481	2,345
Refinery throughput	4,185	4,152	4,365	4,371	4,269	4,546	4,330	4,457	4,395	4,432
Petroleum product sales *(1)*	5,334	5,500	5,585	5,506	5,482	5,814	5,737	5,788	5,679	5,754
Natural gas production					*(millions of cubic feet daily)*					
available for sale	10,724	9,762	9,601	10,424	10,127	11,828	10,128	9,524	10,603	10,515
					(thousands of oil-equivalent barrels daily)					
Oil-equivalent production *(2)*	4,325	3,957	3,811	4,121	4,053	4,248	3,979	3,918	4,248	4,097
					(thousands of metric tons)					
Chemical prime product sales *(1) (3)*	6,173	6,310	6,133	6,309	24,925	6,069	6,078	6,082	6,484	24,713
Summarized financial data										
Sales and other operating					*(millions of dollars)*					
revenue *(4)*	47,105	56,360	56,767	58,376	218,608	64,758	71,360	65,679	57,691	259,488
Gross profit *(5)*	14,072	16,333	16,418	13,379	60,202	19,030	20,362	20,247	16,211	75,850
Net income attributable to										
ExxonMobil *(6)*	1,810	1,700	2,650	1,680	7,840	4,940	4,190	4,240	2,780	16,150
Per share data					*(dollars per share)*					
Earnings per common share *(7)*	0.43	0.41	0.63	0.41	1.88	1.17	1.00	1.01	0.67	3.85
Earnings per common share										
– assuming dilution *(7)*	0.43	0.41	0.63	0.41	1.88	1.17	1.00	1.01	0.67	3.85
Dividends per common share	0.73	0.75	0.75	0.75	2.98	0.69	0.73	0.73	0.73	2.88
Common stock prices										
High	85.10	93.83	95.55	93.22	95.55	93.45	90.09	83.53	87.44	93.45
Low	71.55	81.99	82.29	82.76	71.55	82.68	82.80	66.55	73.03	66.55

(1) Petroleum product and chemical prime product sales data reported net of purchases/sales contracts with the same counterparty.

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

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

(4) Includes amounts for sales-based taxes.

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

(6) Fourth quarter 2016 included an Upstream impairment charge of $2,027 million.

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

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

There were 403,868 registered shareholders of ExxonMobil common stock at December 31, 2016. At January 31, 2017, the registered shareholders of ExxonMobil common stock numbered 402,598.

On January 25, 2017, the Corporation declared a $0.75 dividend per common share, payable March 10, 2017.

FUNCTIONAL EARNINGS	**2016**	**2015**	**2014**
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	(4,151)	(1,079)	5,197
Non-U.S.	4,347	8,180	22,351
Downstream			
United States	1,094	1,901	1,618
Non-U.S.	3,107	4,656	1,427
Chemical			
United States	1,876	2,386	2,804
Non-U.S.	2,739	2,032	1,511
Corporate and financing	(1,172)	(1,926)	(2,388)
Net income attributable to ExxonMobil (U.S. GAAP)	7,840	16,150	32,520
Earnings per common share	1.88	3.85	7.60
Earnings per common share – assuming dilution	1.88	3.85	7.60

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

FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual future financial and operating results or conditions, including demand growth and energy source mix; government policies relating to climate change; project plans, capacities, schedules and costs; production growth and mix; rates of field decline; asset carrying values; proved reserves; financing sources; the resolution of contingencies and uncertain tax positions; and 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 and resulting price impacts; the outcome of commercial negotiations; the impact of fiscal and commercial terms; political or regulatory events; the outcome of exploration and development projects, and other factors discussed herein and in Item 1A. Risk Factors.

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

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

OVERVIEW

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

ExxonMobil, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new energy supplies. The company's integrated business model, with significant investments in Upstream, Downstream and Chemical segments, reduces the Corporation's risk from changes in commodity prices. While commodity prices are volatile on a short-term basis and depend on supply and demand, ExxonMobil's investment decisions are based on our long-term business outlook, using a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting near-term operating and capital objectives in addition to providing the longer-term economic assumptions used for investment evaluation purposes. Volumes are based on individual field production profiles, which are also updated annually. Price ranges for crude oil, natural gas, refined products, and chemical products are based on corporate plan assumptions developed annually by major region and are utilized for investment evaluation purposes. Major investment opportunities are evaluated over a range of economic scenarios. Once major investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

By 2040, the world's population is projected to grow to approximately 9 billion people, or about 1.8 billion more than in 2015. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year. As economies and populations grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 25 percent from 2015 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 technologies and practices as well as lower-emission fuels 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 25 percent from 2015 to 2040. The growth in transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Nearly all the world's transportation fleets will continue to 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 60 percent from 2015 to 2040, led by a doubling of demand 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. The share of coal-fired generation is likely to decline to less than 30 percent of the world's electricity in 2040, versus about 40 percent in 2015, in part as a result of policies to improve air quality as well as reduce greenhouse gas emissions to address the risks of climate change. From 2015 to 2040, the amount of electricity generated using natural gas, nuclear power, and renewables is likely to approximately double, and account for 90 percent of the growth in electricity supplies. By 2040, coal, natural gas and renewables are projected to each be generating in the range of 25-30 percent of electricity worldwide, although significant differences will exist across regions reflecting a wide range of factors including the cost and availability of energy types.

Liquid fuels provide the largest share of global energy supplies today reflecting broad-based availability, affordability, ease of distribution, and fitness as a practical solution to meet a wide variety of needs. By 2040, global demand for liquid fuels is projected to grow to approximately 112 million barrels of oil-equivalent per day, an increase of about 20 percent from 2015. Much of this demand today is met by crude production from traditional conventional sources; these supplies will remain important as significant development activity is expected to offset much of the natural declines from these fields. At the same time, a variety of emerging supply sources – including tight oil, deepwater, oil sands, natural gas liquids and biofuels – are expected to grow significantly to meet rising demand. The world's resource base is sufficient to meet projected demand through

2040 as technology advances continue to expand the availability of economic supply options. However, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel, suitable for a wide variety of applications, and it is expected to be the fastest-growing major fuel source from 2015 to 2040, meeting about 40 percent of global energy demand growth. Global natural gas demand is expected to rise about 45 percent from 2015 to 2040, with about 45 percent of that increase in the Asia Pacific region. Helping meet these needs will be significant growth in supplies of unconventional gas - the natural gas found in shale and other rock formations that was once considered uneconomic to produce. In total, about 60 percent of the growth in natural gas supplies is expected to be from unconventional sources. At the same time, conventionally-produced natural gas is likely to remain the cornerstone of supply, meeting about two-thirds of global demand in 2040. Worldwide liquefied natural gas (LNG) trade will expand significantly, likely reaching more than 2.5 times the level of 2015 by 2040, with much of this supply expected to meet rising demand in Asia Pacific.

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 reach 25 percent by 2040, while the share of coal falls to about 20 percent. Nuclear power is projected to grow significantly, as many nations are likely to expand nuclear capacity to address rising electricity needs as well as energy security and environmental issues. Total renewable energy is likely to reach about 15 percent of total energy by 2040, with biomass, hydro and geothermal contributing a combined share of more than 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase rapidly, growing over 200 percent from 2015 to 2040, when they will be about 4 percent of world energy.

The Corporation anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from reserve increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these resources will be significant. According to the International Energy Agency, the investment required to meet oil and natural gas supply requirements worldwide over the period 2016-2040 will be about $23 trillion (measured in 2015 dollars) or approximately $900 billion per year on average.

International accords and underlying regional and national regulations covering greenhouse gas emissions continue to evolve with uncertain timing and outcome, making it difficult to predict their business impact. For many years, the Corporation has taken into account policies established to reduce energy-related greenhouse gas emissions in its long-term *Outlook for Energy*, which is used as a foundation for assessing the business environment and business strategies and investments. The climate accord reached at the recent Conference of the Parties (COP 21) in Paris set many new goals, and many related policies are still emerging. Our *Outlook* reflects increasingly stringent climate policies and is consistent with the aggregation of Nationally Determined Contributions which were submitted by signatories to the United Nations Framework Convention on Climate Change (UNFCC) 2015 Paris Agreement. Our *Outlook* seeks to identify potential impacts of climate related policies, which often target specific sectors, by using various assumptions and tools including application of a proxy cost of carbon to estimate potential impacts on consumer demands. For purposes of the *Outlook*, a proxy cost on energy-related CO_2 emissions is assumed to reach about $80 per tonne on average in 2040 in OECD nations. China and other leading non-OECD nations are expected to trail OECD policy initiatives. Nevertheless, as people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need. Thus, all practical and economically viable energy sources, both conventional and unconventional, will need to be pursued to continue meeting global energy demand, recognizing the scale and variety of worldwide energy needs as well as the importance of expanding access to modern energy to promote better standards of living for billions of people.

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

Upstream

ExxonMobil continues to maintain a diverse portfolio of exploration and development opportunities, which enables the Corporation to be selective, maximizing shareholder value and mitigating political and technical risks. ExxonMobil's fundamental Upstream business strategies guide our global exploration, development, production, and gas and power marketing activities. These strategies include capturing material and accretive opportunities to continually high-grade the resource portfolio, selectively developing attractive oil and natural gas resources, developing and applying high-impact technologies, and pursuing productivity and efficiency gains. These strategies are underpinned by a relentless focus on operational excellence, 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 and in the type of opportunities from which volumes are produced. Oil equivalent production from North

America is expected to increase over the next several years based on current investment plans, contributing over a third of total production. Further, the proportion of our global production from resource types utilizing specialized technologies such as arctic, deepwater, unconventional drilling and production systems and LNG, is a slight majority of production and is expected to grow over the next few years. We do not anticipate that the expected change in the geographic mix of production volumes, and in the types of opportunities from which volumes will be produced, will have a material impact on the nature and the extent of the risks disclosed in Item 1A. Risk Factors, or result in a material change in our level of unit operating expenses.

The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups; operational outages; reservoir performance; performance of enhanced oil recovery projects; regulatory changes; the impact of fiscal and commercial terms; asset sales; weather events; price effects on production sharing contracts; changes in the amount and timing of capital investments that may vary depending on the oil and gas price environment; and other factors described in Item 1A. Risk Factors.

The upstream industry environment has been challenged in recent years with abundant crude oil supply causing crude oil prices to decrease to levels not seen since 2004, and natural gas prices declined with increased supply. However, current market conditions are not necessarily indicative of future conditions. The markets for crude oil and natural gas have a history of significant price volatility. ExxonMobil believes prices over the long term will continue to be driven by market supply and demand, with the demand side largely being a function of global economic growth. On the supply side, prices may be significantly impacted by political events, the actions of OPEC and other large government resource owners, and other factors. To manage the risks associated with price, ExxonMobil evaluates annual plans and major investments across a range of price scenarios.

Downstream

ExxonMobil's Downstream is a large, diversified business with refining, logistics, and marketing complexes around the world. The Corporation has a presence in mature markets in North America and Europe, as well as in the growing Asia Pacific region.

ExxonMobil's fundamental Downstream business strategies competitively position the company across a range of market conditions. These strategies include targeting best-in-class operations in all aspects of the business, maximizing value from advanced technologies, capitalizing on integration across ExxonMobil businesses, selectively investing for resilient, advantaged returns, operating efficiently and effectively, and providing quality, valued and differentiated products and services to customers.

ExxonMobil's operating results, as noted in Item 2. Properties, reflect 22 refineries, located in 14 countries, with distillation capacity of 4.9 million barrels per day and lubricant basestock manufacturing capacity of 126 thousand barrels per day. ExxonMobil's fuels and lubes marketing businesses have significant global reach, with multiple channels to market serving a diverse customer base. Our portfolio of world-renowned brands includes *Exxon*, *Mobil*, *Esso* and *Mobil 1*.

While demand remained strong in 2016, margins weakened as surplus distillate and gasoline production capacity created high inventories. North American refineries which benefited from cost-competitive feedstock and energy supplies saw lower margins as the differential between Brent and WTI narrowed after the elimination of the U.S. crude export ban. Margins in Europe and Asia weakened versus 2015, but reductions in supply and rising Asia demand kept those markets above bottom-of-cycle conditions seen in 2014. In the near term, we see variability in refining margins, with some regions seeing weaker margins as new capacity additions are expected to outpace growth in global demand for our products, which can also be affected by global economic conditions and regulatory changes.

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

ExxonMobil's long-term outlook is that industry refining margins will remain subject to intense competition as new capacity additions outpace the growth in global demand. ExxonMobil's integration across the value chain, from refining to marketing, enhances overall value in both fuels and lubricants businesses.

As described in more detail in Item 1A. Risk Factors, proposed carbon policy and other climate-related regulations in many countries, as well as the continued growth in biofuels mandates, could have negative impacts on the Downstream business.

In the retail fuels marketing business, product cost volatility has contributed to a decline in margins. In 2016, ExxonMobil expanded its branded retail site network and progressed the multi-year transition of the direct served (i.e., dealer, company-operated) retail network in portions of Europe and Canada to a more capital-efficient Branded Wholesaler model. The company's lubricants business continues to grow, leveraging world-class brands and integration with industry-leading basestock refining capability. ExxonMobil remains a market leader in the high-value synthetic lubricants sector, despite increasing competition.

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. In 2016, the company divested its refinery in Torrance, California. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. In 2016, construction continued on a new delayed coker unit at the refinery in Antwerp, Belgium, to upgrade low-value bunker fuel into higher value diesel products. Construction also progressed on a proprietary hydrocracker at the refinery in Rotterdam, Netherlands, to produce higher value ultra-low sulfur diesel and Group II basestocks. The Taicang, China, lubricants plant expansion was completed in April 2016, doubling the capacity of the facility. The Port Allen Aviation Lubricants Plant in Louisiana achieved full production during the year, and an expansion in Singapore is underway to support demand growth for finished lubricants in key markets. Finally, ExxonMobil announced plans to increase production of ultra-low sulfur fuels at the Beaumont, Texas, refinery by approximately 40,000 barrels per day.

Chemical

Worldwide petrochemical demand remained strong in 2016, led by growing demand from Asia Pacific manufacturers of industrial and consumer products. North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low-cost feedstock and energy. Specialty product margins moderated in 2016 with capacity additions exceeding demand growth.

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

In 2016, we completed startup of the specialty elastomers project at our joint venture facility in Al-Jubail, Saudi Arabia. Construction continued on a major expansion at our Texas facilities, including a new world-scale ethane cracker and polyethylene lines, to capitalize on low-cost feedstock and energy supplies in North America and to meet rapidly growing demand for premium polymers. Construction of new halobutyl rubber and hydrocarbon resin units also progressed in Singapore to further extend our specialty product capacity in Asia Pacific. The company also announced plans to expand its polyethylene plant in Beaumont, Texas, and specialty elastomers plant in Newport, Wales.

REVIEW OF 2016 AND 2015 RESULTS

	2016	2015	2014
		(millions of dollars)	
Earnings (U.S. GAAP)			
Net income attributable to ExxonMobil (U.S. GAAP)	7,840	16,150	32,520

Upstream

	2016	2015	2014
		(millions of dollars)	
Upstream			
United States	(4,151)	(1,079)	5,197
Non-U.S.	4,347	8,180	22,351
Total	196	7,101	27,548

2016

Upstream earnings were $196 million in 2016 and included an asset impairment charge of $2,027 million mainly related to dry gas operations with undeveloped acreage in the Rocky Mountains region of the U.S. Current year earnings were down $6,905 million from 2015. Lower realizations decreased earnings by $5.3 billion. Favorable volume and mix effects increased earnings by $130 million. The impairment charge reduced earnings by $2 billion. All other items increased earnings by $310 million, primarily due to lower expenses partly offset by the absence of favorable tax items from the prior year. On an oil equivalent basis, production of 4.1 million barrels per day was down slightly compared to 2015. Liquids production of 2.4 million barrels per day increased 20,000 barrels per day with increased project volumes, mainly in Canada, Indonesia and Nigeria, partly offset by field decline, the impact from Canadian wildfires, and downtime notably in Nigeria. Natural gas production of 10.1 billion cubic feet per day decreased 388 million cubic feet per day from 2015 as field decline, regulatory restrictions in the Netherlands and divestments were partly offset by higher project volumes and work programs. U.S. Upstream earnings declined $3,072 million from 2015 to a loss of $4,151 million, and included the impairment charge of $2,027 million. Earnings outside the U.S. were $4,347 million, down $3,833 million from the prior year.

2015

Upstream earnings were $7,101 million, down $20,447 million from 2014. Lower realizations decreased earnings by $18.8 billion. Favorable volume and mix effects increased earnings by $810 million, including contributions from new developments. All other items decreased earnings by $2.4 billion, primarily due to lower asset management gains and approximately $500 million of lower favorable one-time tax effects, partly offset by lower expenses of about $230 million. On an oil-equivalent basis, production of 4.1 million barrels per day was up 3.2 percent compared to 2014. Liquids production of 2.3 million barrels per day increased 234,000 barrels per day, with project ramp-up and entitlement effects partly offset by field decline. Natural gas production of 10.5 billion cubic feet per day decreased 630 million cubic feet per day from 2014 as regulatory restrictions in the Netherlands and field decline were partly offset by project ramp-up, work programs and entitlement effects. U.S. Upstream earnings declined $6,276 million from 2014 to a loss of $1,079 million in 2015. Earnings outside the U.S. were $8,180 million, down $14,171 million from the prior year.

Upstream Additional Information

	2016	2015
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production) *(1)*		
Prior year	4,097	3,969
Entitlements - Net Interest	9	(14)
Entitlements - Price / Spend / Other	(23)	168
Quotas	-	-
Divestments	(34)	(25)
United Arab Emirates Onshore Concession Expiry	-	(6)
Growth / Other	4	5
Current Year	4,053	4,097

(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 cumulative investment returns or production volumes achieve defined thresholds, changes in equity upon achieving pay-out in partner investment carry situations, equity redeterminations as specified in venture agreements, or as a result of the termination or expiry of a concession. Once a net interest change has occurred, it typically will not be reversed by subsequent events, such as lower crude oil prices.

Entitlements - Price, Spend and Other are changes to ExxonMobil's share of production volumes resulting from temporary changes to non-operational volume-determining 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 royalty 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 also 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 a field or 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.

Downstream

	2016	2015	2014
		(millions of dollars)	
Downstream			
United States	1,094	1,901	1,618
Non-U.S.	3,107	4,656	1,427
Total	4,201	6,557	3,045

2016

Downstream earnings of $4,201 million decreased $2,356 million from 2015. Weaker refining and marketing margins decreased earnings by $3.8 billion, while volume and mix effects increased earnings by $560 million. All other items increased earnings by $920 million, mainly reflecting gains from divestments, notably in Canada. Petroleum product sales of 5.5 million barrels per day were 272,000 barrels per day lower than 2015 mainly reflecting the divestment of refineries in California and Louisiana. U.S. Downstream earnings were $1,094 million, a decrease of $807 million from 2015. Non-U.S. Downstream earnings were $3,107 million, down $1,549 million from the prior year.

2015

Downstream earnings of $6,557 million increased $3,512 million from 2014. Stronger margins increased earnings by $4.1 billion, while volume and mix effects decreased earnings by $200 million. All other items decreased earnings by $420 million, reflecting nearly $560 million in higher maintenance expense and about $280 million in unfavorable inventory impacts, partly offset by favorable foreign exchange effects. Petroleum product sales of 5.8 million barrels per day were 121,000 barrels per day lower than 2014. U.S. Downstream earnings were $1,901 million, an increase of $283 million from 2014. Non-U.S. Downstream earnings were $4,656 million, up $3,229 million from the prior year.

Chemical

	2016	2015	2014
		(millions of dollars)	
Chemical			
United States	1,876	2,386	2,804
Non-U.S.	2,739	2,032	1,511
Total	4,615	4,418	4,315

2016

Chemical earnings of $4,615 million increased $197 million from 2015. Stronger margins increased earnings by $440 million. Favorable volume and mix effects increased earnings by $100 million. All other items decreased earnings by $340 million, primarily due to the absence of U.S. asset management gains. Prime product sales of 24.9 million metric tons were up 212,000 metric tons from 2015. U.S. Chemical earnings were $1,876 million, down $510 million from 2015 reflecting the absence of asset management gains. Non-U.S. Chemical earnings of $2,739 million were $707 million higher than the prior year.

2015

Chemical earnings of $4,418 million increased $103 million from 2014. Stronger margins increased earnings by $590 million. Favorable volume and mix effects increased earnings by $220 million. All other items decreased earnings by $710 million, reflecting about $680 million in unfavorable foreign exchange effects and $220 million in negative tax and inventory impacts, partly offset by asset management gains. Prime product sales of 24.7 million metric tons were up 478,000 metric tons from 2014. U.S. Chemical earnings were $2,386 million, down $418 million from 2014. Non-U.S. Chemical earnings were $2,032 million, $521 million higher than the prior year.

Corporate and Financing

	2016	2015	2014
		(millions of dollars)	
Corporate and financing	(1,172)	(1,926)	(2,388)

2016

Corporate and financing expenses of $1,172 million in 2016 were $754 million lower than 2015 mainly reflecting favorable non-U.S. tax items.

2015

Corporate and financing expenses were $1,926 million in 2015 compared to $2,388 million in 2014, with the decrease due mainly to net favorable tax-related items.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2016	2015	2014
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	22,082	30,344	45,116
Investing activities	(12,403)	(23,824)	(26,975)
Financing activities	(9,293)	(7,037)	(17,888)
Effect of exchange rate changes	(434)	(394)	(281)
Increase/(decrease) in cash and cash equivalents	(48)	(911)	(28)
		(December 31)	
Cash and cash equivalents	3,657	3,705	4,616
Cash and cash equivalents - restricted	-	-	42
Total cash and cash equivalents	3,657	3,705	4,658

Total cash and cash equivalents were $3.7 billion at the end of 2016, essentially in line with the prior year. The major sources of funds in 2016 were net income including noncontrolling interests of $8.4 billion, the adjustment for the noncash provision of $22.3 billion for depreciation and depletion, proceeds from asset sales of $4.3 billion, and a net debt increase of $4.3 billion. The major uses of funds included spending for additions to property, plant and equipment of $16.2 billion, dividends to shareholders of $12.5 billion, the adjustment for non-cash deferred income tax credits of $4.4 billion, and a change in working capital, excluding cash and debt, of $1.4 billion.

Total cash and cash equivalents were $3.7 billion at the end of 2015, $1.0 billion lower than the prior year. The major sources of funds in 2015 were net income including noncontrolling interests of $16.6 billion, the adjustment for the noncash provision of $18.0 billion for depreciation and depletion, and a net debt increase of $9.3 billion. The major uses of funds included spending for additions to property, plant and equipment of $26.5 billion, the purchase of shares of ExxonMobil stock of $4.0 billion, dividends to shareholders of $12.1 billion and a change in working capital, excluding cash and debt, of $3.1 billion.

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, 2016, the Corporation had unused committed short-term lines of credit of $5.5 billion and unused committed long-term lines of credit of $0.3 billion. Cash that may be temporarily available as surplus to the Corporation's immediate needs is carefully managed through counterparty quality and investment guidelines to ensure it is secure and readily available to meet the Corporation's cash requirements and to optimize returns.

To support cash flows in future periods the Corporation will need to continually find and develop new fields, and continue to develop and apply new technologies and recovery processes to existing fields, in order to maintain or increase production. After a period of production at plateau rates, it is the nature of oil and gas fields eventually to produce at declining rates for the remainder of their economic life. Averaged over all the Corporation's existing oil and gas fields and without new projects, ExxonMobil's production is expected to decline at an average of approximately 3 percent per year over the next few years. Decline rates can vary widely by individual field due to a number of factors, including, but not limited to, the type of reservoir, fluid properties, recovery mechanisms, work activity, and age of the field. Furthermore, the Corporation's net interest in production for individual fields can vary with price and 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. The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups; operational outages; reservoir performance; performance of enhanced oil recovery projects; regulatory changes; the impact of fiscal and commercial terms; asset sales; weather events; price effects on production sharing contracts; and changes in the amount and timing of investments that may vary depending on the oil and gas price environment. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please refer to Item 1A. Risk Factors for a more complete discussion of risks.

The Corporation's financial strength enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2016 were $19.3 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment level of $22 billion in 2017. The Corporation is emerging from several years of high capital expenditure levels that supported major long-plateau production projects coming on line. Lower levels of capital spending over the next few years, partly due to cost savings and capital efficiencies, are not expected to delay major project schedules nor have a material effect on our volume capacity outlook.

Actual spending could vary depending on the progress of individual projects and property acquisitions. The Corporation has a large and diverse portfolio of development projects and exploration opportunities, which helps mitigate the overall political and technical risks of the Corporation's Upstream segment and associated cash flow. Further, due to its financial strength, debt capacity and diverse portfolio of opportunities, the risk associated with failure or delay of any single project would not have a significant impact on the Corporation's liquidity or ability to generate sufficient cash flows for operations and its fixed commitments.

Cash Flow from Operating Activities

2016

Cash provided by operating activities totaled $22.1 billion in 2016, $8.3 billion lower than 2015. The major source of funds was net income including noncontrolling interests of $8.4 billion, a decrease of $8.2 billion. The noncash provision for depreciation and depletion was $22.3 billion, up $4.3 billion from the prior year. The adjustment for net gains on asset sales was $1.7 billion while the adjustment for deferred income tax credits was $4.4 billion. Changes in operational working capital, excluding cash and debt, decreased cash in 2016 by $1.4 billion.

2015

Cash provided by operating activities totaled $30.3 billion in 2015, $14.8 billion lower than 2014. The major source of funds was net income including noncontrolling interests of $16.6 billion, a decrease of $17.1 billion. The noncash provision for depreciation and depletion was $18.0 billion, up $0.8 billion from the prior year. The adjustment for net gains on asset sales was $0.2 billion compared to an adjustment of $3.2 billion in 2014. Changes in operational working capital, excluding cash and debt, decreased cash in 2015 by $3.1 billion.

Cash Flow from Investing Activities

2016

Cash used in investment activities netted to $12.4 billion in 2016, $11.4 billion lower than 2015. Spending for property, plant and equipment of $16.2 billion decreased $10.3 billion from 2015. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $4.3 billion compared to $2.4 billion in 2015. Additional investments and advances were $0.8 billion higher in 2016.

2015

Cash used in investment activities netted to $23.8 billion in 2015, $3.2 billion lower than 2014. Spending for property, plant and equipment of $26.5 billion decreased $6.5 billion from 2014. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $2.4 billion compared to $4.0 billion in 2014. Additional investments and advances were $1.0 billion lower in 2015, while collection of advances was $2.5 billion lower in 2015.

Cash Flow from Financing Activities

2016

Cash used in financing activities was $9.3 billion in 2016, $2.3 billion higher than 2015. Dividend payments on common shares increased to $2.98 per share from $2.88 per share and totaled $12.5 billion. Total debt increased $4.1 billion to $42.8 billion at year-end. The first quarter issuance of $12.0 billion in long-term debt was partly offset by repayments of $8.0 billion in commercial paper and other short-term debt during the year.

ExxonMobil share of equity decreased $3.5 billion to $167.3 billion. The addition to equity for earnings was $7.8 billion. This was offset by reductions for distributions to ExxonMobil shareholders of $12.5 billion, all in the form of dividends. Foreign exchange translation effects of $0.3 billion for the stronger U.S. currency reduced equity, while a $1.6 billion change in the funded status of the postretirement benefits reserves increased equity.

During 2016, Exxon Mobil Corporation acquired 12 million shares of its common stock for the treasury at a gross cost of $1.0 billion. These purchases were made to offset shares or units settled in shares issued in conjunction with the company's benefit plans and programs. Shares outstanding were reduced from 4,156 million to 4,148 million at the end of 2016.

2015

Cash used in financing activities was $7.0 billion in 2015, $10.9 billion lower than 2014. Dividend payments on common shares increased to $2.88 per share from $2.70 per share and totaled $12.1 billion, a pay-out of 75 percent of net income. During the first quarter of 2015, the Corporation issued $8.0 billion of long-term debt. Total debt increased $9.6 billion to $38.7 billion at year-end.

ExxonMobil share of equity decreased $3.6 billion to $170.8 billion. The addition to equity for earnings was $16.2 billion. This was offset by reductions for distributions to ExxonMobil shareholders of $15.1 billion, composed of $12.1 billion in dividends and $3.0 billion of share purchases of ExxonMobil stock to reduce shares outstanding. Foreign exchange translation effects of $8.2 billion for the stronger U.S. currency reduced equity, while a $3.6 billion change in the funded status of the postretirement benefits reserves increased equity.

During 2015, Exxon Mobil Corporation acquired 48 million shares of its common stock for the treasury at a gross cost of $4.0 billion. These purchases were to reduce the number of shares outstanding and to offset shares or units settled in shares issued in conjunction with company benefit plans and programs. Shares outstanding were reduced by 1.1 percent from 4,201 million to 4,156 million at the end of 2015. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2016. The table combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

		Payments Due by Period				
Commitments	**Note Reference Number**	**2017**	**2018-2019**	**2020-2021**	**2022 and Beyond**	**Total**
			(millions of dollars)			
Long-term debt *(1)*	14	-	8,623	4,149	16,160	28,932
– Due in one year *(2)*	6	2,960	-	-	-	2,960
Asset retirement obligations *(3)*	9	891	1,852	1,425	9,075	13,243
Pension and other postretirement obligations *(4)*	17	2,015	2,017	1,977	14,700	20,709
Operating leases *(5)*	11	1,103	1,133	561	1,014	3,811
Take-or-pay and unconditional purchase obligations *(6)*		2,904	5,082	3,985	9,609	21,580
Firm capital commitments *(7)*		6,432	2,781	779	421	10,413

This table excludes commodity purchase obligations (volumetric commitments but no fixed or minimum price) which are resold shortly after purchase, either in an active, highly liquid market or under long-term, unconditional sales contracts with similar pricing terms. Examples include long-term, noncancelable LNG and natural gas purchase commitments and commitments to purchase refinery products at market prices. Inclusion of such commitments would not be meaningful in assessing liquidity and cash flow, because these purchases will be offset in the same periods by cash received from the related sales transactions. The table also excludes unrecognized tax benefits totaling $9.5 billion as of December 31, 2016, 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 $1,225 million.*

(2) *The amount due in one year is included in notes and loans payable of $13,830 million.*

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

(4) *The amount by which the benefit obligations exceeded the fair value of fund assets for certain U.S. and non-U.S. pension and other postretirement plans at year-end. The payments by period include expected contributions to funded pension plans in 2017 and estimated benefit payments for unfunded plans in all years.*

(5) *Minimum commitments for operating leases, shown on an undiscounted basis, cover drilling equipment, tankers, service stations and other properties. Total includes $836 million related to drilling rigs and related equipment.*

(6) *Take-or-pay obligations are noncancelable, long-term commitments for goods and services. Unconditional purchase obligations are those long-term commitments that are noncancelable or cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. The undiscounted obligations of $21,580 million mainly pertain to pipeline, manufacturing supply and terminal agreements.*

(7) *Firm capital commitments represent legally binding payment obligations to third parties where agreements specifying all significant terms have been executed for the construction and purchase of fixed assets and other permanent investments. In certain cases where the Corporation executes contracts requiring commitments to a work scope, those commitments have been included to the extent that the amounts and timing of payments can be reliably estimated. Firm capital commitments, shown on an undiscounted basis, totaled $10.4 billion, including $2.8 billion in the U.S. Firm capital commitments for the non-U.S. Upstream of $6.9 billion were primarily associated with projects in the United Arab Emirates, Africa, Malaysia, Canada, Australia and Norway. The Corporation expects to fund the majority of these commitments 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, 2016, for guarantees relating to notes, loans and performance under contracts (Note 16). Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure. These guarantees are not reasonably likely to have a material effect on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Financial Strength

On December 31, 2016, the Corporation's unused short-term committed lines of credit totaled $5.5 billion (Note 6) and unused long-term committed lines of credit totaled $0.3 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.

	2016	2015	2014
Fixed-charge coverage ratio (times)	5.7	17.6	46.9
Debt to capital (percent)	19.7	18.0	13.9
Net debt to capital (percent)	18.4	16.5	11.9

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

Litigation and Other Contingencies

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

CAPITAL AND EXPLORATION EXPENDITURES

	2016			2015		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
			(millions of dollars)			
Upstream *(1)*	3,518	11,024	14,542	7,822	17,585	25,407
Downstream	839	1,623	2,462	1,039	1,574	2,613
Chemical	1,553	654	2,207	1,945	898	2,843
Other	93	-	93	188	-	188
Total	6,003	13,301	19,304	10,994	20,057	31,051

(1) Exploration expenses included.

Capital and exploration expenditures in 2016 were $19.3 billion, as the Corporation continued to pursue opportunities to find and produce new supplies of oil and natural gas to meet global demand for energy. The Corporation anticipates an investment level of $22 billion in 2017. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $14.5 billion in 2016 was down 43 percent from 2015, reflecting key project start-ups and capital efficiencies. Investments in 2016 included U.S. onshore drilling and world-class projects in Kazakhstan, 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 69 percent of total proved reserves at year-end 2016, and has been over 60 percent for the last ten years.

Capital investments in the Downstream totaled $2.5 billion in 2016, a decrease of $0.2 billion from 2015, mainly reflecting lower refining project spending. Chemical capital expenditures of $2.2 billion decreased $0.6 billion from 2015 resulting from progression of major expansions.

TAXES

	2016	2015	2014
		(millions of dollars)	
Income taxes	(406)	5,415	18,015
Effective income tax rate	*13%*	*34%*	*41%*
Sales-based taxes	21,090	22,678	29,342
All other taxes and duties	28,265	29,790	35,515
Total	48,949	57,883	82,872

2016

Income, sales-based and all other taxes and duties totaled $48.9 billion in 2016, a decrease of $8.9 billion or 15 percent from 2015. Income tax expense, both current and deferred, was a credit of $0.4 billion, $5.8 billion lower than 2015, reflecting lower pre-tax income. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 13 percent compared to 34 percent in the prior year due primarily to a lower share of earnings in higher tax jurisdictions, favorable one-time items, and the impact of the U.S. Upstream impairment charge. Sales-based and all other taxes and duties of $49.4 billion in 2016 decreased $3.1 billion.

2015

Income, sales-based and all other taxes and duties totaled $57.9 billion in 2015, a decrease of $25.0 billion or 30 percent from 2014. Income tax expense, both current and deferred, was $5.4 billion, $12.6 billion lower than 2014, as a result of lower earnings and a lower effective tax rate. The effective tax rate was 34 percent compared to 41 percent in the prior year due primarily to a lower share of earnings in higher tax jurisdictions. Sales-based and all other taxes and duties of $52.5 billion in 2015 decreased $12.4 billion as a result of lower sales realizations.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2016	2015
	(millions of dollars)	
Capital expenditures	1,436	1,869
Other expenditures	3,451	3,777
Total	4,887	5,646

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels, as well as projects to monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions, and expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2016 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.9 billion, of which $3.5 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to remain relatively flat at approximately $5 billion in 2017 and 2018. Capital expenditures are expected to account for approximately 30 percent of the total.

Environmental Liabilities

The Corporation accrues environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for probable environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency has identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at these multiparty sites could mitigate ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil's operations or financial condition. Consolidated company provisions made in 2016 for environmental liabilities were $665 million ($371 million in 2015) and the balance sheet reflects accumulated liabilities of $852 million as of December 31, 2016, and $837 million as of December 31, 2015.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2016	2015	2014
Crude oil and NGL ($ per barrel)	38.15	44.77	87.42
Natural gas ($ per thousand cubic feet)	2.25	2.95	4.68

(1) Consolidated subsidiaries.

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. In the Upstream, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $400 million annual after-tax effect on Upstream consolidated plus equity company earnings. Similarly, a $0.10 per thousand cubic feet change in the worldwide average gas realization would have approximately a $150 million annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide broad indicators of changes in the earnings experienced in any particular period.

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

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

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

Although price levels of crude oil and natural gas may rise or fall significantly over the short to medium term due to global economic conditions, political events, decisions by OPEC and other major government resource owners and other factors, industry economics over the long term will continue to be driven by market supply and demand. Accordingly, the Corporation evaluates the viability of its major investments over a range of prices.

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 resulting in an efficient capital base.

Risk Management

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

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

The Corporation conducts business in many foreign currencies and is subject to exchange rate risk on cash flows related to sales, expenses, financing and investment transactions. The impacts of fluctuations in exchange rates on ExxonMobil's geographically and functionally diverse operations are varied and often offsetting in amount. The Corporation makes limited use of currency exchange contracts to mitigate the impact of changes in currency values, and exposures related to the Corporation's limited use of the currency exchange contracts are not material.

Inflation and Other Uncertainties

The general rate of inflation in many major countries of operation has remained moderate over the past few years, and the associated impact on non-energy costs has generally been mitigated by cost reductions from efficiency and productivity improvements. Beginning several years ago, an extended period of increased demand for certain services and materials resulted in higher operating and capital costs. More recently, multiple market changes, including general commodity price decreases, lower oil prices and reduced upstream industry activity, have contributed to lower prices for oilfield services and materials. The Corporation works to minimize costs in all commodity price environments through its economies of scale in global procurement and its efficient project management practices.

RECENTLY ISSUED ACCOUNTING STANDARDS

In May 2014, the Financial Accounting Standards Board issued a new standard, *Revenue from Contracts with Customers*. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry specific requirements, and expands disclosure requirements. The standard is required to be adopted beginning January 1, 2018. "Sales and Other Operating Revenue" on the Consolidated Statement of Income includes sales, excise and value-added taxes on sales transactions. When the Corporation adopts the standard, revenue will exclude sales-based taxes collected on behalf of third parties. This change in reporting will not impact earnings. The Corporation expects to adopt the standard using the Modified Retrospective method, under which prior years' results are not restated, but supplemental information on the impact of the new standard is provided for 2018 results. The Corporation continues to evaluate other areas of the standard, which are not expected to have a material effect on the Corporation's financial statements.

In February 2016, the Financial Accounting Standards Board issued a new standard, *Leases*. The standard requires that all leases with an initial term greater than one year be recorded on the balance sheet as a lease asset and a lease liability. The standard is required to be adopted beginning January 1, 2019, with early adoption permitted. ExxonMobil is evaluating the standard and its effect on the Corporation's financial statements and plans to adopt it in 2019.

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 Natural Gas Reserves

The estimation of proved reserves is an ongoing process based on rigorous technical evaluations, commercial and market assessment, and detailed analysis of well information such as flow rates and reservoir pressure declines, among other factors. 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 Global Reserves Group which has significant technical experience, culminating in reviews with and approval by senior management. Notably, the Corporation does not use specific quantitative reserve targets to determine compensation. Key features of the reserve estimation process are covered in Disclosure of Reserves in Item 2.

Oil and natural gas reserves include both proved and unproved reserves.

- Proved oil and natural gas reserves are determined in accordance with Securities and Exchange Commission (SEC) requirements. Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic and operating conditions and government regulations. Proved reserves are determined using the average of first-of-month oil and natural gas prices during the reporting year.

  Proved reserves can be further subdivided into developed and undeveloped reserves. Proved developed reserves include amounts which are expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include amounts expected to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion. Proved undeveloped reserves are recognized only if a development plan has been adopted indicating that the reserves are scheduled to be drilled within five years, unless specific circumstances support a longer period of time.

  The percentage of proved developed reserves was 69 percent of total proved reserves at year-end 2016 (including both consolidated and equity company reserves), a reduction from 73 percent in 2015, and has been over 60 percent for the last ten years. Although the Corporation is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in long-term oil and natural gas prices.

- Unproved reserves are quantities of oil and natural gas with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that, together with proved reserves, are as likely as not to be recovered.

Revisions in previously estimated volumes of proved reserves for existing fields can occur 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 the average of first-of-month oil and natural gas prices and / or costs that are used in the estimation of reserves. Revisions can also result from significant changes in development strategy or production equipment and facility capacity.

As a result of very low prices during 2016, under the SEC definition of proved reserves, certain quantities of oil and natural gas that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2016. Amounts no longer qualifying as proved reserves include the entire 3.5 billion barrels of bitumen at Kearl, in Canada. In addition, 0.8 billion barrels of oil equivalent across the remainder of North America no longer qualify as proved reserves mainly due to the acceleration of the projected end-of-field-life. Among the factors that would result in these amounts being recognized again as proved reserves at some point in the future are a recovery in average price levels, a further decline in costs, and / or operating efficiencies. Under the terms of certain contractual arrangements or government royalty regimes, lower prices can also increase proved reserves attributable to ExxonMobil. We do not expect the downward revision of reported proved reserves under SEC definitions to affect the operation of the underlying projects or to alter our outlook for future production volumes.

Supplemental information regarding oil and natural gas results of operations, capitalized costs and reserves is provided following the notes to consolidated financial statements.

Unit-of-Production Depreciation

Oil and natural gas reserve quantities are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. Depreciation is calculated by taking the ratio of asset cost to total proved reserves or proved developed reserves applied to actual production. The volumes produced and asset cost are known, while proved reserves are based on estimates that are subject to some variability.

In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the Corporation uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life.

To the extent that proved reserves for a property are entirely de-booked and that property continues to produce, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a quantity of proved reserves greater than zero, appropriately adjusted for production and technical changes. The effect of this approach on the Corporation's 2017 depreciation expense versus 2016 is anticipated to be immaterial.

Impairment

The Corporation tests assets or groups of assets for recoverability whenever events or circumstances indicate that the carrying amounts may not be recoverable. Among the events or changes in circumstances which could indicate that the carrying value of an asset or asset group may not be recoverable are the following:

- a significant decrease in the market price of a long-lived asset;
- a significant adverse change in the extent or manner in which an asset is being used or in its physical condition including a significant decrease in current and projected reserve volumes;
- a significant adverse change in legal factors or in the business climate that could affect the value, including an adverse action or assessment by a regulator;
- an accumulation of project costs significantly in excess of the amount originally expected;
- a current-period operating loss combined with a history and forecast of operating or cash flow losses; and
- a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses and other profitability reviews assist the Corporation in assessing whether the carrying amounts of any of its assets may not be recoverable.

In general, the Corporation does not view temporarily low prices or margins as an indication of impairment. Management does not believe that lower prices are sustainable if energy is to be delivered with supply security to meet global demand over the long term. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. Because the lifespans of the vast majority of the Corporation's major assets are measured in decades, the value of these assets is predominantly based on long-term views of future commodity prices and production costs. During the lifespan of these major assets, the Corporation expects that oil and gas prices will experience significant volatility, and consequently these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether the events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the Corporation considers recent periods of operating losses in the context of its longer-term view of prices. While near-term prices are subject to wide fluctuations, longer-term price views are more stable and meaningful for purposes of assessing future cash flows.

When the industry experiences a prolonged and deep reduction in commodity prices, the market supply and demand conditions may result in changes to the Corporation's long-term price or margin assumptions it uses for its capital investment decisions. To the extent those changes result in a significant reduction in the mid-point of its long-term oil, natural gas price or margin ranges, the Corporation may consider that situation, in conjunction with other events and changes in circumstances such as a history of operating losses, an indicator of potential impairment for certain assets.

In the Upstream, the standardized measure of discounted cash flows included in the Supplemental Information on Oil and Gas Exploration and Production Activities is required to use prices based on the average of first-of-month prices. These prices represent discrete points in time and could be higher or lower than the Corporation's long-term price assumptions which are used for impairment assessments. The Corporation believes the standardized measure does not provide a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its oil and gas reserves and therefore does not consider it relevant in determining whether events or changes in circumstances indicate the need for an impairment assessment.

If events or circumstances indicate that the carrying value may not be recoverable, the Corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, 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. Cash flows used in recoverability assessments are based on the Corporation's assumptions which are developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the Corporation's assumptions of future crude oil and natural gas commodity prices, refining and chemical margins, volumes, costs, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

An asset group is impaired if its undiscounted cash flows are less than the asset's carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. Fair value is based on market prices if an active market exists for the asset group, or discounted cash flows using a discount rate commensurate with the risk. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Continued weakness in the upstream industry environment during 2016, continued weak financial results for several assets in North America, and a reduction in the mid-point of the ranges of the Corporation's long-term oil and natural gas prices developed as part of its annual planning and budgeting cycle led the Corporation to conclude that the facts and circumstances supported performing an impairment assessment of certain long-lived assets, notably North America natural gas assets and certain other assets across the remainder of its Upstream operations. The assessment reflected long-term crude and natural gas prices which are consistent with the mid-point of the ranges that management uses to evaluate investment opportunities and which are in the range of long-term price forecasts published by third-party industry experts and government agencies. This assessment indicated that the vast majority of asset groups have future undiscounted cash flow estimates exceeding carrying values. However, the carrying values for certain asset groups in the United States exceeded the estimated cash flows. As a result, the Corporation's fourth quarter 2016 results include an after-tax charge of $2 billion to reduce the carrying value of those assets to fair value. The asset groups subject to this impairment charge are primarily dry gas operations in the Rocky Mountains region of the United States with large undeveloped acreage positions.

The assessment of fair values required the use of Level 3 inputs. The principal parameters used to establish fair values included estimates of both proved and unproved reserves, future commodity prices which were consistent with the average of third-party industry experts and government agencies, drilling and development costs, discount rates ranging from 5.5 percent to 8 percent depending on the characteristics of the asset group, and comparable market transactions. Due to the inherent difficulty in predicting future commodity prices, and the relationship between industry prices and costs, it is not practicable to reasonably estimate the existence or range of any potential future impairment charges related to the Corporation's long-lived assets.

Inventories

Crude oil, products and merchandise inventories are carried at the lower of current market value or cost (generally determined under the last-in, first-out method – LIFO).

Asset Retirement Obligations

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

Suspended Exploratory Well Costs

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

Consolidations

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

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

Pension Benefits

The Corporation and its affiliates sponsor nearly 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 flow rather than a separate pension fund because applicable tax rules and regulatory practices do not encourage advance funding. Book reserves are established for these plans. The portion of the pension cost attributable to employee service is expensed as services are rendered. The portion attributable to the increase in pension obligations due to the passage of time is expensed over the term of the obligations, which ends when all benefits are paid. The primary difference in pension expense for unfunded versus funded plans is that pension expense for funded plans also includes a credit for the expected long-term return on fund assets.

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

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

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations and the long-term rate for future salary increases. Pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long-term expected earnings rate on U.S. pension plan assets in 2016 was 6.50 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 5 percent and 8 percent, respectively. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pension fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the long-term rate of return on assets would increase annual pension expense by approximately $160 million before tax.

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

Litigation Contingencies

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

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

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

Tax Contingencies

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

The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. A reserve is established for the difference between a position taken or expected to be taken in an income tax return and the amount recognized in the financial statements. The Corporation's unrecognized tax benefits and a description of open tax years are summarized in Note 19.

Foreign Currency Translation

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

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation's Chief Executive Officer, Principal Financial Officer, and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2016.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2016, as stated in their report included in the Financial Section of this report.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Exxon Mobil Corporation:

In our opinion, the accompanying Consolidated Balance Sheets and the related Consolidated Statements of Income, Comprehensive Income, Changes in Equity, and Cash Flows present fairly, in all material respects, the financial position of Exxon Mobil Corporation and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Corporation's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Corporation's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 22, 2017

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2016	2015	2014
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*		218,608	259,488	394,105
Income from equity affiliates	7	4,806	7,644	13,323
Other income		2,680	1,750	4,511
Total revenues and other income		226,094	268,882	411,939
Costs and other deductions				
Crude oil and product purchases		104,171	130,003	225,972
Production and manufacturing expenses		31,927	35,587	40,859
Selling, general and administrative expenses		10,799	11,501	12,598
Depreciation and depletion	9	22,308	18,048	17,297
Exploration expenses, including dry holes		1,467	1,523	1,669
Interest expense		453	311	286
Sales-based taxes *(1)*	19	21,090	22,678	29,342
Other taxes and duties	19	25,910	27,265	32,286
Total costs and other deductions		218,125	246,916	360,309
Income before income taxes		7,969	21,966	51,630
Income taxes	19	(406)	5,415	18,015
Net income including noncontrolling interests		8,375	16,551	33,615
Net income attributable to noncontrolling interests		535	401	1,095
Net income attributable to ExxonMobil		7,840	16,150	32,520
Earnings per common share *(dollars)*	12	1.88	3.85	7.60
Earnings per common share - assuming dilution *(dollars)*	12	1.88	3.85	7.60

(1) Sales and other operating revenue includes sales-based taxes of $21,090 million for 2016, $22,678 million for 2015 and $29,342 million for 2014.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2016	2015	2014
		(millions of dollars)	
Net income including noncontrolling interests	8,375	16,551	33,615
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(174)	(9,303)	(5,847)
Adjustment for foreign exchange translation (gain)/loss included in net income	-	(14)	152
Postretirement benefits reserves adjustment (excluding amortization)	493	2,358	(4,262)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	1,086	1,448	1,111
Unrealized change in fair value of stock investments	-	33	(63)
Realized (gain)/loss from stock investments included in net income	-	27	3
Total other comprehensive income	1,405	(5,451)	(8,906)
Comprehensive income including noncontrolling interests	9,780	11,100	24,709
Comprehensive income attributable to noncontrolling interests	668	(496)	421
Comprehensive income attributable to ExxonMobil	9,112	11,596	24,288

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2016	Dec. 31 2015
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		3,657	3,705
Notes and accounts receivable, less estimated doubtful amounts	6	21,394	19,875
Inventories			
Crude oil, products and merchandise	3	10,877	12,037
Materials and supplies		4,203	4,208
Other current assets		1,285	2,798
Total current assets		41,416	42,623
Investments, advances and long-term receivables	8	35,102	34,245
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	244,224	251,605
Other assets, including intangibles, net		9,572	8,285
Total assets		330,314	336,758
Liabilities			
Current liabilities			
Notes and loans payable	6	13,830	18,762
Accounts payable and accrued liabilities	6	31,193	32,412
Income taxes payable		2,615	2,802
Total current liabilities		47,638	53,976
Long-term debt	14	28,932	19,925
Postretirement benefits reserves	17	20,680	22,647
Deferred income tax liabilities	19	34,041	36,818
Long-term obligations to equity companies		5,124	5,417
Other long-term obligations		20,069	21,165
Total liabilities		156,484	159,948
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		12,157	11,612
Earnings reinvested		407,831	412,444
Accumulated other comprehensive income		(22,239)	(23,511)
Common stock held in treasury (3,871 million shares in 2016 and 3,863 million shares in 2015)		(230,424)	(229,734)
ExxonMobil share of equity		167,325	170,811
Noncontrolling interests		6,505	5,999
Total equity		173,830	176,810
Total liabilities and equity		330,314	336,758

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2016	2015	2014
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		8,375	16,551	33,615
Adjustments for noncash transactions				
Depreciation and depletion	9	22,308	18,048	17,297
Deferred income tax charges/(credits)		(4,386)	(1,832)	1,540
Postretirement benefits expense in excess of/(less than) net payments		(329)	2,153	524
Other long-term obligation provisions in excess of/(less than) payments		(19)	(380)	1,404
Dividends received greater than/(less than) equity in current earnings of equity companies		(579)	(691)	(358)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		(2,090)	4,692	3,118
- Inventories		(388)	(379)	(1,343)
- Other current assets		171	45	(68)
Increase/(reduction) - Accounts and other payables		915	(7,471)	(6,639)
Net (gain) on asset sales	5	(1,682)	(226)	(3,151)
All other items - net	5	(214)	(166)	(823)
Net cash provided by operating activities		22,082	30,344	45,116
Cash flows from investing activities				
Additions to property, plant and equipment	5	(16,163)	(26,490)	(32,952)
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	5	4,275	2,389	4,035
Decrease/(increase) in restricted cash and cash equivalents		-	42	227
Additional investments and advances		(1,417)	(607)	(1,631)
Collection of advances		902	842	3,346
Net cash used in investing activities		(12,403)	(23,824)	(26,975)
Cash flows from financing activities				
Additions to long-term debt	5	12,066	8,028	5,731
Reductions in long-term debt		-	(26)	(69)
Reductions in short-term debt		(314)	(506)	(745)
Additions/(reductions) in commercial paper, and debt with three months or less maturity	5	(7,459)	1,759	2,049
Cash dividends to ExxonMobil shareholders		(12,453)	(12,090)	(11,568)
Cash dividends to noncontrolling interests		(162)	(170)	(248)
Tax benefits related to stock-based awards		-	2	115
Common stock acquired		(977)	(4,039)	(13,183)
Common stock sold		6	5	30
Net cash used in financing activities		(9,293)	(7,037)	(17,888)
Effects of exchange rate changes on cash		(434)	(394)	(281)
Increase/(decrease) in cash and cash equivalents		(48)	(911)	(28)
Cash and cash equivalents at beginning of year		3,705	4,616	4,644
Cash and cash equivalents at end of year		3,657	3,705	4,616

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	Total Equity
	(millions of dollars)						
Balance as of December 31, 2013	10,077	387,432	(10,725)	(212,781)	174,003	6,492	180,495
Amortization of stock-based awards	780	-	-	-	780	-	780
Tax benefits related to stock-based awards	49	-	-	-	49	-	49
Other	(114)	-	-	-	(114)	-	(114)
Net income for the year	-	32,520	-	-	32,520	1,095	33,615
Dividends - common shares	-	(11,568)	-	-	(11,568)	(248)	(11,816)
Other comprehensive income	-	-	(8,232)	-	(8,232)	(674)	(8,906)
Acquisitions, at cost	-	-	-	(13,183)	(13,183)	-	(13,183)
Dispositions	-	-	-	144	144	-	144
Balance as of December 31, 2014	10,792	408,384	(18,957)	(225,820)	174,399	6,665	181,064
Amortization of stock-based awards	828	-	-	-	828	-	828
Tax benefits related to stock-based awards	116	-	-	-	116	-	116
Other	(124)	-	-	-	(124)	-	(124)
Net income for the year	-	16,150	-	-	16,150	401	16,551
Dividends - common shares	-	(12,090)	-	-	(12,090)	(170)	(12,260)
Other comprehensive income	-	-	(4,554)	-	(4,554)	(897)	(5,451)
Acquisitions, at cost	-	-	-	(4,039)	(4,039)	-	(4,039)
Dispositions	-	-	-	125	125	-	125
Balance as of December 31, 2015	11,612	412,444	(23,511)	(229,734)	170,811	5,999	176,810
Amortization of stock-based awards	796	-	-	-	796	-	796
Tax benefits related to stock-based awards	30	-	-	-	30	-	30
Other	(281)	-	-	-	(281)	-	(281)
Net income for the year	-	7,840	-	-	7,840	535	8,375
Dividends - common shares	-	(12,453)	-	-	(12,453)	(162)	(12,615)
Other comprehensive income	-	-	1,272	-	1,272	133	1,405
Acquisitions, at cost	-	-	-	(977)	(977)	-	(977)
Dispositions	-	-	-	287	287	-	287
Balance as of December 31, 2016	12,157	407,831	(22,239)	(230,424)	167,325	6,505	173,830

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2013	8,019	(3,684)	4,335
Acquisitions	-	(136)	(136)
Dispositions	-	2	2
Balance as of December 31, 2014	8,019	(3,818)	4,201
Acquisitions	-	(48)	(48)
Dispositions	-	3	3
Balance as of December 31, 2015	8,019	(3,863)	4,156
Acquisitions	-	(12)	(12)
Dispositions	-	4	4
Balance as of December 31, 2016	8,019	(3,871)	4,148

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

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 2016 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation

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

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

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

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

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

Revenue Recognition

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

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

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

Sales-Based Taxes

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

Derivative Instruments

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

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

Fair Value

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

Inventories

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

Property, Plant and Equipment

Cost Basis. 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 its completion as a producing well and where the Corporation is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred. Development costs, including costs of productive wells and development dry holes, are capitalized.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration.

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 the unit-of-production rates based on the amount of proved developed reserves of oil and gas that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank. In the event that the unit-of-production method does not result in an equitable allocation of cost over the economic life of an upstream asset, an alternative method is used. The straight-line method is used in limited situations where the expected life of the asset does not reasonably correlate with that of the underlying reserves. For example, certain assets used in the production of oil and natural gas have a shorter life than the reserves, and as such, the Corporation uses straight-line depreciation to ensure the asset is fully depreciated by the end of its useful life.

Under the SEC definition of proved reserves, certain quantities of oil and natural gas did not qualify as proved reserves at year-end 2016, the substantial majority of which relates to the Kearl oil sands operation, where no proved reserves remain. To the extent that proved reserves for a property are entirely de-booked and that property continues to produce, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a quantity of proved reserves greater than zero, appropriately adjusted for production and technical changes.

Investments in refinery, chemical process, and lubes basestock manufacturing equipment are generally depreciated on a straight-line basis over a 25-year life. Service station buildings and fixed improvements generally are depreciated over a 20-year life. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

Impairment Assessment. The Corporation tests assets or groups of assets for recoverability whenever events or circumstances indicate that the carrying amounts may not be recoverable. Among the events or changes in circumstances which could indicate that the carrying value of an asset or asset group may not be recoverable are the following:

- a significant decrease in the market price of a long-lived asset;
- a significant adverse change in the extent or manner in which an asset is being used or in its physical condition including a significant decrease in current and projected reserve volumes;
- a significant adverse change in legal factors or in the business climate that could affect the value, including an adverse action or assessment by a regulator;
- an accumulation of project costs significantly in excess of the amount originally expected;
- a current-period operating loss combined with a history and forecast of operating or cash flow losses; and
- a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

The Corporation performs asset valuation analyses on an ongoing basis as a part of its asset management program. These analyses and other profitability reviews assist the Corporation in assessing whether the carrying amounts of any of its assets may not be recoverable.

In general, the Corporation does not view temporarily low prices or margins as an indication of impairment. Management does not believe that lower prices are sustainable if energy is to be delivered with supply security to meet global demand over the long term. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand. On the supply side, industry production from mature fields is declining, but this is being offset by production from new discoveries and field developments. OPEC production policies also have an impact on world oil supplies. The demand side is largely a function of global economic growth. Because the lifespans of the vast majority of the Corporation's major assets are measured in decades, the value of these assets is predominantly based on long-term views of future commodity prices and production costs. During the lifespan of these major assets, the Corporation expects that oil and gas prices will experience significant volatility, and consequently these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether the events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the Corporation considers recent periods of operating losses in the context of its longer-term view of prices. While near-term prices are subject to wide fluctuations, longer term price views are more stable and meaningful for purposes of assessing future cash flows.

When the industry experiences a prolonged and deep reduction in commodity prices, the market supply and demand conditions may result in changes to the Corporation's long-term price or margin assumptions it uses for its capital investment decisions. To the extent those changes result in a significant reduction in the mid-point of its long-term oil, natural gas price or margin ranges, the Corporation may consider that situation, in conjunction with other events and changes in circumstances such as a history of operating losses, an indicator of potential impairment for certain assets.

In the Upstream, the standardized measure of discounted cash flows included in the Supplemental Information on Oil and Gas Exploration and Production activities is required to use prices based on the average of first-of-month prices. These prices represent discrete points in time and could be higher or lower than the Corporation's long-term price assumptions which are used for impairment assessments. The Corporation believes the standardized measure does not provide a reliable estimate of the expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its oil and gas reserves and therefore does not consider it relevant in determining whether events or changes in circumstances indicate the need for an impairment assessment.

If events or circumstances indicate that the carrying value may not be recoverable, the Corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, 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. Cash flows used in recoverability assessments are based on the Corporation's assumptions which are developed in the annual planning and budgeting process, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the Corporation's assumptions of future crude oil and natural gas commodity prices, refining and chemical margins, volumes, costs, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

An asset group is impaired if its undiscounted cash flows are less than the asset's carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. Fair value is based on market prices if an active market exists for the asset group, or discounted cash flows using a discount rate commensurate with the risk. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Other. 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.

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 values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. The costs associated with these liabilities are capitalized as part of the related assets and depreciated. Over time, the liabilities are accreted for the change in their present value.

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

Foreign Currency Translation

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

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

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

Stock-Based Payments

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

2. Accounting Changes

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, 2018. "Sales and Other Operating Revenue" on the Consolidated Statement of Income includes sales, excise and value-added taxes on sales transactions. When the Corporation adopts the standard, revenue will exclude sales-based taxes collected on behalf of third parties. This change in reporting will not impact earnings. The Corporation expects to adopt the standard using the Modified Retrospective method, under which prior years' results are not restated, but supplemental information on the impact of the new standard is provided for 2018 results. The Corporation continues to evaluate other areas of the standard which are not expected to have a material effect on the Corporation's financial statements.

In February 2016, the Financial Accounting Standards Board issued a new standard, *Leases*. The standard requires that all leases with an initial term greater than one year be recorded on the balance sheet as a lease asset and a lease liability. The standard is required to be adopted beginning January 1, 2019, with early adoption permitted. ExxonMobil is evaluating the standard and its effect on the Corporation's financial statements and plans to adopt it in 2019.

Effective September 30, 2016, the Corporation early-adopted Accounting Standard Update no. 2015-17 *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* on a prospective basis. This update eliminates the requirement to classify deferred tax assets and liabilities as current and noncurrent, and instead requires all deferred tax assets and liabilities to be classified as noncurrent. See Note 19.

3. Miscellaneous Financial Information

Research and development expenses totaled $1,058 million in 2016, $1,008 million in 2015 and $971 million in 2014.

Net income included before-tax aggregate foreign exchange transaction gains of $29 million in 2016, and losses of $119 million in 2015 and $225 million in 2014, respectively.

In 2016, 2015 and 2014, net income included losses of $295 million and $186 million, and a gain of $187 million, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $8.1 billion and $4.5 billion at December 31, 2016, and 2015, respectively.

Crude oil, products and merchandise as of year-end 2016 and 2015 consist of the following:

	2016	**2015**
	(billions of dollars)	
Crude oil	3.9	4.2
Petroleum products	3.7	4.1
Chemical products	2.8	2.7
Gas/other	0.5	1.0
Total	10.9	12.0

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	Cumulative Foreign Exchange Translation Adjustment	Post-retirement Benefits Reserves Adjustment	Unrealized Change in Stock Investments	Total
		(millions of dollars)		
Balance as of December 31, 2013	(846)	(9,879)	-	(10,725)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(5,258)	(4,132)	(63)	(9,453)
Amounts reclassified from accumulated other comprehensive income	152	1,066	3	1,221
Total change in accumulated other comprehensive income	(5,106)	(3,066)	(60)	(8,232)
Balance as of December 31, 2014	(5,952)	(12,945)	(60)	(18,957)
Balance as of December 31, 2014	(5,952)	(12,945)	(60)	(18,957)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(8,204)	2,202	33	(5,969)
Amounts reclassified from accumulated other comprehensive income	(14)	1,402	27	1,415
Total change in accumulated other comprehensive income	(8,218)	3,604	60	(4,554)
Balance as of December 31, 2015	(14,170)	(9,341)	-	(23,511)
Balance as of December 31, 2015	(14,170)	(9,341)	-	(23,511)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(331)	552	-	221
Amounts reclassified from accumulated other comprehensive income	-	1,051	-	1,051
Total change in accumulated other comprehensive income	(331)	1,603	-	1,272
Balance as of December 31, 2016	(14,501)	(7,738)	-	(22,239)

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)	2016	2015	2014
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	-	14	(152)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs *(1)*	(1,531)	(2,066)	(1,571)
Realized change in fair value of stock investments included in net income (Statement of Income line: Other income)	-	(42)	(5)

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

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	2016	2015	2014
		(millions of dollars)	
Foreign exchange translation adjustment	43	170	292
Postretirement benefits reserves adjustment (excluding amortization)	(247)	(1,192)	2,009
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(445)	(618)	(460)
Unrealized change in fair value of stock investments	-	(17)	34
Realized change in fair value of stock investments included in net income	-	(15)	(2)
Total	(649)	(1,672)	1,873

5. Cash Flow Information

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

For 2016, the "Net (gain) on asset sales" on the Consolidated Statement of Cash Flows includes before-tax amounts from the sale of service stations in Canada, the sale of Upstream properties in the U.S., and the sale of aviation fueling operations across multiple countries. For 2015, the number includes before-tax amounts from the sale of service stations in Europe, the sale of Upstream properties in the U.S., the sale of ExxonMobil's interests in Chemical and Refining joint ventures, and the sale of the Torrance refinery. For 2014, the number includes before-tax gains from the sale of Hong Kong power operations, additional proceeds related to the 2013 sale of a partial interest in Iraq, the sale of Downstream affiliates in the Caribbean and the sale or exchange of Upstream properties in the U.S., Canada, and Malaysia. These net gains are reported in "Other income" on the Consolidated Statement of Income.

In 2016, the "Additions/(reductions) in commercial paper, and debt with three months or less maturity" on the Consolidated Statement of Cash Flows includes a net $608 million addition of commercial paper with maturity over three months. The gross amount issued was $3.9 billion, while the gross amount repaid was $3.3 billion. In 2015, the number includes a net $358 million addition of commercial paper with maturity over three months. The gross amount issued was $8.1 billion, while the gross amount repaid was $7.7 billion.

In 2015, ExxonMobil completed an asset exchange that resulted in value received of approximately $500 million including $100 million in cash. The non-cash portion was not included in the "Sales of subsidiaries, investments, and property, plant and equipment" or the "All other items-net" lines on the Statement of Cash Flows. Capital leases of approximately $1 billion were not included in the "Additions to long-term debt" or "Additions to property, plant and equipment" lines on the Statement of Cash Flows.

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.

	2016	2015	2014
		(millions of dollars)	
Cash payments for interest	818	586	380
Cash payments for income taxes	4,214	7,269	18,085

6. Additional Working Capital Information

	Dec. 31 2016	Dec. 31 2015
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $75 million and $107 million	16,033	13,243
Other, less reserves of $627 million and $4 million	5,361	6,632
Total	21,394	19,875
Notes and loans payable		
Bank loans	143	231
Commercial paper	10,727	17,973
Long-term debt due within one year	2,960	558
Total	13,830	18,762
Accounts payable and accrued liabilities		
Trade payables	17,801	18,074
Payables to equity companies	4,748	4,639
Accrued taxes other than income taxes	2,653	2,937
Other	5,991	6,762
Total	31,193	32,412

The Corporation has short-term committed lines of credit of $5.5 billion which were unused as of December 31, 2016. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 0.6 percent and 0.4 percent at December 31, 2016, and 2015, respectively.

7. Equity Company Information

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

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

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 14 percent, 15 percent and 14 percent in the years 2016, 2015 and 2014, respectively.

In 2013 and 2014, the Corporation and Rosneft established various entities to conduct exploration and research activities. Periods of disproportionate funding will result in the Corporation recognizing, during the early phases of the projects, an investment that is larger than its equity share in these entities. These joint ventures are considered Variable 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. With respect to the foregoing, each joint venture continues to comply with all applicable laws, rules, and regulations. The Corporation's maximum before-tax exposure to loss from these joint ventures as of December 31, 2016, is $1.0 billion.

Equity Company Financial Summary	**2016 Total**	**2016 ExxonMobil Share**	**2015 Total**	**2015 ExxonMobil Share**	**2014 Total**	**2014 ExxonMobil Share**
			(millions of dollars)			
Total revenues	80,247	24,668	111,866	34,297	183,708	55,855
Income before income taxes	22,269	6,509	36,379	10,670	65,549	19,014
Income taxes	6,334	1,701	11,048	3,019	20,520	5,684
Income from equity affiliates	15,935	4,808	25,331	7,651	45,029	13,330
Current assets	34,412	11,392	32,879	11,244	49,905	16,802
Long-term assets	109,646	32,357	109,684	32,878	110,754	33,619
Total assets	144,058	43,749	142,563	44,122	160,659	50,421
Current liabilities	20,507	5,765	22,947	6,738	37,333	11,472
Long-term liabilities	62,110	17,288	60,388	17,165	66,231	19,470
Net assets	61,441	20,696	59,228	20,219	57,095	19,479

A list of significant equity companies as of December 31, 2016, 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	
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 Italia s.r.l.	50
Infineum Singapore Pte. Ltd.	50
Infineum USA L.P.	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2016	Dec. 31, 2015
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	20,810	20,337
Advances	9,443	9,110
Total equity company investments and advances	30,253	29,447
Companies carried at cost or less and stock investments carried at fair value	154	274
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $4,141 million and $3,040 million	4,695	4,524
Total	35,102	34,245

9. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	December 31, 2016 Cost	December 31, 2016 Net	December 31, 2015 Cost	December 31, 2015 Net
	(millions of dollars)			
Upstream	355,265	195,904	347,821	203,822
Downstream	47,915	20,588	50,742	21,330
Chemical	34,098	17,401	32,481	16,247
Other	16,637	10,331	16,293	10,206
Total	453,915	244,224	447,337	251,605

Continued weakness in the upstream industry environment during 2016, continued weak financial results for several assets in North America, and a reduction in the mid-point of the ranges of the Corporation's long-term oil and natural gas prices developed as part of its annual planning and budgeting cycle led the Corporation to conclude that the facts and circumstances supported performing an impairment assessment of certain long-lived assets, notably North America natural gas assets and certain other assets across the remainder of its Upstream operations. The assessment reflected long-term crude and natural gas prices which are consistent with the mid-point of the ranges that management uses to evaluate investment opportunities and which are in the range of long-term price forecasts published by third-party industry experts and government agencies. This assessment indicated that the vast majority of asset groups have future undiscounted cash flow estimates exceeding carrying values. However, the carrying values for certain asset groups in the United States exceeded the estimated cash flows. As a result, the Corporation's fourth quarter 2016 results include a before-tax charge of $3.3 billion to reduce the carrying value of those assets to fair value. The asset groups subject to this impairment charge are primarily dry gas operations in the Rocky Mountains region of the United States with large undeveloped acreage positions. The impairment charge is recognized in the line "Depreciation and depletion" on the Consolidated Statement of Income and recorded in "Accumulated depreciation and depletion".

The assessment of fair values required the use of Level 3 inputs. The principal parameters used to establish fair values included estimates of both proved and unproved reserves, future commodity prices which were consistent with the average of third-party industry experts and government agencies, drilling and development costs, discount rates ranging from 5.5 percent to 8 percent depending on the characteristics of the asset group, and comparable market transactions. Due to the inherent difficulty in predicting future commodity prices, and the relationship between industry prices and costs, it is not practicable to reasonably estimate the existence or range of any potential future impairment charges related to the Corporation's long-lived assets.

Accumulated depreciation and depletion totaled $209,691 million at the end of 2016 and $195,732 million at the end of 2015. Interest capitalized in 2016, 2015 and 2014 was $708 million, $482 million and $344 million, respectively.

Asset Retirement Obligations

The Corporation incurs retirement obligations for certain assets. The fair values of these obligations are recorded as liabilities on a discounted basis, which is typically at the time the assets are installed. In the estimation of fair value, the Corporation uses assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; technical assessments of the assets; estimated amounts and timing of settlements; discount rates; and inflation rates. Asset retirement obligations incurred in the current period were Level 3 fair value measurements. The costs associated with these liabilities are capitalized as part of the related assets and depreciated as the reserves are produced. Over time, the liabilities are accreted for the change in their present value.

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

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

	2016	2015
	(millions of dollars)	
Beginning balance	13,704	13,424
Accretion expense and other provisions	740	775
Reduction due to property sales	(134)	(208)
Payments made	(549)	(928)
Liabilities incurred	204	283
Foreign currency translation	(513)	(931)
Revisions	(209)	1,289
Ending balance	13,243	13,704

10. Accounting for Suspended Exploratory Well Costs

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

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

Change in capitalized suspended exploratory well costs:

	2016	2015	2014
		(millions of dollars)	
Balance beginning at January 1	4,372	3,587	2,707
Additions pending the determination of proved reserves	180	847	1,095
Charged to expense	(111)	(5)	(28)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	-	(43)	(160)
Divestments/Other	36	(14)	(27)
Ending balance at December 31	4,477	4,372	3,587
Ending balance attributed to equity companies included above	707	696	645

Period end capitalized suspended exploratory well costs:

	2016	2015	2014
		(millions of dollars)	
Capitalized for a period of one year or less	180	847	1,095
Capitalized for a period of between one and five years	2,981	2,386	1,659
Capitalized for a period of between five and ten years	911	826	544
Capitalized for a period of greater than ten years	405	313	289
Capitalized for a period greater than one year - subtotal	4,297	3,525	2,492
Total	4,477	4,372	3,587

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, which includes the Rosneft joint venture exploration activity (refer to the relevant portion of Note 7).

	2016	2015	2014
Number of projects with first capitalized well drilled in the preceding 12 months	2	4	8
Number of projects that have exploratory well costs capitalized for a period of greater than 12 months	58	55	53
Total	60	59	61

Of the 58 projects that have exploratory well costs capitalized for a period greater than 12 months as of December 31, 2016, 16 projects have drilling in the preceding 12 months or exploratory activity either planned in the next two years or subject to sanctions. The remaining 42 projects are those with completed exploratory activity progressing toward development.

The table below provides additional detail for those 42 projects, which total $1,998 million.

Country/Project	Dec. 31, 2016	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	7	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/ planned infrastructure.
- SE Longtom	11	2010	Gas field near Tuna development, awaiting capacity in existing/planned infrastructure.
- SE Remora	34	2010	Gas field near Marlin development, awaiting capacity in existing/planned infrastructure.
Canada			
- Horn River	213	2009 - 2012	Evaluating development alternatives to tie into planned infrastructure.
Indonesia			
- Alas Tua West	16	2010	Evaluating development plan to tie into planned production facilities.
- Cepu Gas	29	2008 - 2011	Development activity under way, while continuing commercial discussions with the government.
- Kedung Keris	11	2011	Development activity under way 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.
- Kalamkas	18	2006 - 2009	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
Malaysia			
- 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.
- OML 138 Ukot SW	41	2014	Evaluating development plan for tieback to existing production facilities.
- OML 138 Ukot SS	13	2015	Evaluating development plan for tieback to existing production facilities.
- Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
- Satellite Field Development Phase 2	12	2013	Evaluating development plan for tie into planned production facilities.
- Other (4 projects)	13	2002	Evaluating and pursuing development of several additional discoveries.
Norway			
- Gamma	13	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- Lavrans	16	1995 - 1999	Evaluating development plan, awaiting capacity in existing Kristin production facility.
- Other (7 projects)	26	2008 - 2014	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.

Country/Project	Dec. 31, 2016	Years Wells Drilled	Comment
	(millions of dollars)		
Republic of Congo			
- Mer Tres Profonde Sud	56	2000 - 2007	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
Tanzania			
- Tanzania Block 2	435	2012 - 2015	Evaluating development alternatives while continuing discussions with government regarding development plan.
- Tanzania Block 2 Ullage	88	2013 - 2014	Evaluating development alternatives while continuing discussions with government regarding development plan.
United Kingdom			
- Phyllis	6	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.
Vietnam			
- Blue Whale	296	2011 - 2015	Development planning activity under way, while continuing commercial discussions with the government.
Total 2016 (42 projects)	1,998		

11. Leased Facilities

At December 31, 2016, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering drilling equipment, tankers, service stations and other properties with minimum undiscounted lease commitments totaling $3,811 million as indicated in the table. Estimated related sublease rental income from noncancelable subleases totals $30 million.

	Lease Payments Under Minimum Commitments		
	Drilling Rigs and Related Equipment	Other	Total
		(millions of dollars)	
2017	333	770	1,103
2018	153	529	682
2019	98	353	451
2020	87	239	326
2021	52	183	235
2022 and beyond	113	901	1,014
Total	836	2,975	3,811

Net rental cost under both cancelable and noncancelable operating leases incurred during 2016, 2015 and 2014 were as follows:

	2016	2015	2014
		(millions of dollars)	
Rental cost			
Drilling rigs and related equipment	1,274	1,853	1,763
Other (net of sublease rental income)	1,817	2,076	2,262
Total	3,091	3,929	4,025

12. Earnings Per Share

Earnings per common share	2016	2015	2014
Net income attributable to ExxonMobil *(millions of dollars)*	7,840	16,150	32,520
Weighted average number of common shares outstanding *(millions of shares)*	4,177	4,196	4,282
Earnings per common share *(dollars) (1)*	1.88	3.85	7.60
Dividends paid per common share *(dollars)*	2.98	2.88	2.70

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

13. Financial Instruments and Derivatives

Financial Instruments. The fair value of financial instruments is determined by reference to observable market data and other valuation techniques as appropriate. The only category 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 $28.0 billion and $18.9 billion at December 31, 2016, and 2015, respectively, as compared to recorded book values of $27.7 billion and $18.7 billion at December 31, 2016, and 2015, respectively. The increase in the estimated fair value and book value of long-term debt reflects the Corporation's issuance of $12.0 billion of long-term debt in the first quarter of 2016.

The fair value of long-term debt by hierarchy level at December 31, 2016, is: Level 1 $27,825 million; Level 2 $137 million; and Level 3 $6 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 liability of $22 million at year-end 2016 and a net asset of $21 million at year-end 2015. 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 $(81) million, $39 million and $110 million during 2016, 2015 and 2014, respectively. Income statement effects associated with derivatives are usually recorded either in "Sales and other operating revenue" or "Crude oil and product purchases".

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

14. Long-Term Debt

At December 31, 2016, long-term debt consisted of $28,257 million due in U.S. dollars and $675 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $2,960 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 $12.0 billion of long-term debt in the first quarter of 2016. The amounts of long-term debt, including capitalized lease obligations, maturing in each of the four years after December 31, 2017, in millions of dollars, are: 2018 – $4,737; 2019 – $3,886; 2020 – $1,609; and 2021 – $2,540. At December 31, 2016, the Corporation's unused long-term credit lines were $0.3 billion.

Summarized long-term debt at year-end 2016 and 2015 are shown in the table below:

	Average Rate *(1)*	2016	2015
		(millions of dollars)	
Exxon Mobil Corporation			
0.921% notes due 2017		-	1,500
Floating-rate notes due 2017		-	750
1.305% notes due 2018		1,600	1,600
1.439% notes due 2018		1,000	-
Floating-rate notes due 2018 *(Issued 2016)*	1.337%	750	-
Floating-rate notes due 2018 *(Issued 2015)*	0.735%	500	500
1.819% notes due 2019		1,750	1,750
1.708% notes due in 2019		1,250	-
Floating-rate notes due 2019 *(Issued 2014)*	0.833%	500	500
Floating-rate notes due 2019 *(Issued 2016)*	1.518%	250	-
1.912% notes due 2020		1,500	1,500
2.222% notes due 2021		2,500	-
2.397% notes due 2022		1,150	1,150
Floating-rate notes due 2022	1.055%	500	500
2.726% notes due 2023		1,250	-
3.176% notes due 2024		1,000	1,000
2.709% notes due 2025		1,750	1,750
3.043% notes due 2026		2,500	-
3.567% notes due 2045		1,000	1,000
4.114% notes due 2046		2,500	-
XTO Energy Inc. *(2)*			
6.250% senior notes due 2017		-	465
5.500% senior notes due 2018		371	377
6.500% senior notes due 2018		453	463
6.100% senior notes due 2036		197	198
6.750% senior notes due 2037		304	307
6.375% senior notes due 2038		233	235
Mobil Corporation			
8.625% debentures due 2021		249	249
Industrial revenue bonds due 2017-2051	0.322%	2,559	2,611
Other U.S. dollar obligations		103	198
Other foreign currency obligations		57	84
Capitalized lease obligations	9.142%	1,225	1,238
Debt issuance costs *(3)*		(69)	-
Total long-term debt		28,932	19,925

(1) Average effective interest rate for debt and average imputed interest rate for capital leases at December 31, 2016.

(2) Includes premiums of $138 million in 2016 and $179 million in 2015.

(3) Debt issuance costs at December 31, 2015 were $60 million and are not significant to the Corporation.

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of award. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2016, remaining shares available for award under the 2003 Incentive Program were 93 million.

Restricted Stock and Restricted Stock Units. Awards totaling 9,583 thousand, 9,681 thousand, and 9,775 thousand of restricted (nonvested) common stock units were granted in 2016, 2015 and 2014, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

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

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2016.

Restricted stock and units outstanding	**2016** Shares	**2016** Weighted Average Grant-Date Fair Value per Share
	(thousands)	*(dollars)*
Issued and outstanding at January 1	44,063	84.85
2015 award issued in 2016	9,680	81.27
Vested	(9,816)	83.20
Forfeited	(94)	84.81
Issued and outstanding at December 31	43,833	84.43

Value of restricted stock and units	**2016**	**2015**	**2014**
Grant price *(dollars)*	87.70	81.27	95.20
Value at date of grant:		*(millions of dollars)*	
Restricted stock and units settled in stock	771	727	858
Units settled in cash	69	60	73
Total value	840	787	931

As of December 31, 2016, there was $2,197 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.5 years. The compensation cost charged against income for the restricted stock and restricted stock units was $880 million, $855 million and $831 million for 2016, 2015 and 2014, respectively. The income tax benefit recognized in income related to this compensation expense was $80 million, $78 million and $76 million for the same periods, respectively. The fair value of shares and units vested in 2016, 2015 and 2014 was $851 million, $808 million and $946 million, respectively. Cash payments of $67 million, $64 million and $73 million for vested restricted stock units settled in cash were made in 2016, 2015 and 2014, respectively.

16. Litigation and Other Contingencies

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

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2016, for guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure.

	Dec. 31, 2016		
	Equity Company Obligations *(1)*	Other Third-Party Obligations	Total
		(millions of dollars)	
Guarantees			
Debt-related	118	30	148
Other	2,413	3,975	6,388
Total	2,531	4,005	6,536

(1) ExxonMobil share.

Additionally, the Corporation and its affiliates have numerous long-term sales and purchase commitments in their various business activities, all of which are expected to be fulfilled with no adverse consequences material to the Corporation's operations or financial condition.

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

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID). 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 $1.6 billion as of the date of expropriation, June 27, 2007, and interest from that date at 3.25% compounded annually until the date of payment in full. The Tribunal also noted that one of the Cerro Negro Project agreements provides a mechanism to prevent double recovery between the ICSID award and all or part of an earlier award of $908 million to an ExxonMobil affiliate, Mobil Cerro Negro, Ltd., against PdVSA and a PdVSA affiliate, PdVSA CN, in an arbitration under the rules of the International Chamber of Commerce.

On June 12, 2015, the Tribunal rejected in its entirety Venezuela's October 23, 2014, application to revise the ICSID award. The Tribunal also lifted the associated stay of enforcement that had been entered upon the filing of the application to revise.

Still pending is Venezuela's February 2, 2015, application to ICSID seeking annulment of the ICSID award. That application alleges 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. A separate stay of the ICSID award was entered following the filing of the annulment application. On July 7, 2015, the ICSID Committee considering the annulment application heard arguments from the parties on whether to lift the stay of the award associated with that application. On July 28, 2015, the Committee issued an order that would lift the stay of enforcement unless, within 30 days, Venezuela delivered a commitment to pay the award if the application to annul is denied. On September 17, 2015, the Committee ruled that Venezuela had complied with the requirement to submit a written commitment to pay the award and so left the stay of enforcement in place. A hearing on Venezuela's application for annulment was held March 8-9, 2016.

The United States District Court for the Southern District of New York entered judgment on the ICSID award on October 10, 2014. Motions filed by Venezuela to vacate that judgment on procedural grounds and 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, were denied on February 13, 2015, and March 4, 2015, respectively. On March 9, 2015, Venezuela filed a notice of appeal of the court's actions on the two motions. Oral arguments on this appeal were held before the United States Court of Appeals for the Second Circuit on January 7, 2016.

The District Court's judgment on the ICSID award is currently stayed until such time as ICSID's stay of the award entered following Venezuela's filing of its application to annul has 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 operations or financial condition.

An affiliate of ExxonMobil is one of the Contractors under a Production Sharing Contract (PSC) with the Nigerian National Petroleum Corporation (NNPC) covering the Erha block located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the block and owns a 56.25 percent interest under the PSC. The Contractors are in dispute with NNPC regarding NNPC's lifting of crude oil in excess of its entitlement under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuja, Nigeria, under the Nigerian Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholding the Contractors' position in all material respects and awarding damages to the Contractors jointly in an amount of approximately $1.8 billion plus $234 million in accrued interest. The Contractors petitioned a Nigerian federal court for enforcement of the award, and NNPC petitioned the same court to have the award set aside. On May 22, 2012, the court set aside the award. The Contractors appealed that judgment to the Court of Appeal, Abuja Judicial Division. On July 22, 2016, the Court of Appeal upheld the decision of the lower court setting aside the award. On October 21, 2016, the Contractors appealed the decision to the Supreme Court of Nigeria. In June 2013, the Contractors filed a lawsuit against NNPC in the Nigerian federal high court in order to preserve their ability to seek enforcement of the PSC in the courts if necessary. In October 2014, the Contractors filed suit in the United States District Court for the Southern District of New York to enforce, if necessary, the arbitration award against NNPC assets residing within that jurisdiction. NNPC has moved to dismiss the lawsuit. The stay in the proceedings in the Southern District of New York has been lifted. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, regardless of the outcome of enforcement proceedings, the Corporation does not expect the proceedings to have a material effect upon the Corporation's operations or financial condition.

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2016	2015	2016	2015	2016	2015
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	4.25	4.25	3.00	3.60	4.25	4.25
Long-term rate of compensation increase	5.75	5.75	4.00	4.80	5.75	5.75
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	19,583	20,529	25,117	30,047	8,282	9,436
Service cost	810	864	585	689	153	170
Interest cost	793	785	844	850	344	346
Actuarial loss/(gain)	250	(545)	1,409	(1,517)	(560)	(617)
Benefits paid *(1) (2)*	(1,476)	(2,050)	(1,228)	(1,287)	(537)	(482)
Foreign exchange rate changes	-	-	(1,520)	(3,242)	16	(106)
Amendments, divestments and other	-	-	(11)	(423)	102	(465)
Benefit obligation at December 31	19,960	19,583	25,196	25,117	7,800	8,282
Accumulated benefit obligation at December 31	16,245	15,666	22,867	22,362	-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2016 and 2015, other postretirement benefits paid are net of $22 million and $15 million of Medicare subsidy receipts, respectively.

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

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.5 percent in 2018 and subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $76 million and the postretirement benefit obligation by $862 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $58 million and the postretirement benefit obligation by $687 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2016	2015	2016	2015	2016	2015
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	10,985	12,915	18,417	20,095	414	468
Actual return on plan assets	949	(307)	2,443	918	20	-
Foreign exchange rate changes	-	-	(1,452)	(2,109)	-	-
Company contribution	2,068	-	492	515	36	42
Benefits paid *(1)*	(1,209)	(1,623)	(857)	(890)	(59)	(96)
Other	-	-	-	(112)	-	-
Fair value at December 31	12,793	10,985	19,043	18,417	411	414

(1) Benefit payments for funded plans.

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2016	2015	2016	2015
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(4,306)	(5,782)	212	(588)
Unfunded plans	(2,861)	(2,816)	(6,365)	(6,112)
Total	(7,167)	(8,598)	(6,153)	(6,700)

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.			
	2016	2015	2016	2015	2016	2015
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(7,167)	(8,598)	(6,153)	(6,700)	(7,389)	(7,868)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	-	-	1,035	454	-	-
Current liabilities	(409)	(311)	(294)	(299)	(361)	(363)
Postretirement benefits reserves	(6,758)	(8,287)	(6,894)	(6,855)	(7,028)	(7,505)
Total recorded	(7,167)	(8,598)	(6,153)	(6,700)	(7,389)	(7,868)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	5,354	6,138	5,629	6,413	1,468	2,171
Prior service cost	15	21	(123)	(83)	(430)	(460)
Total recorded in accumulated other comprehensive income	5,369	6,159	5,506	6,330	1,038	1,711

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

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

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2016	2015	2014	2016	2015	2014	2016	2015	2014
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					(percent)				
Discount rate	4.25	4.00	5.00	3.60	3.10	4.30	4.25	4.00	5.00
Long-term rate of return on funded assets	6.50	7.00	7.25	5.25	5.90	6.30	6.50	7.00	7.25
Long-term rate of compensation increase	5.75	5.75	5.75	4.80	5.30	5.40	5.75	5.75	5.75
Components of net periodic benefit cost					(millions of dollars)				
Service cost	810	864	677	585	689	590	153	170	140
Interest cost	793	785	807	844	850	1,138	344	346	383
Expected return on plan assets	(726)	(830)	(799)	(927)	(1,094)	(1,193)	(25)	(28)	(37)
Amortization of actuarial loss/(gain)	492	544	409	536	730	628	153	206	116
Amortization of prior service cost	6	6	8	54	87	120	(30)	(24)	14
Net pension enhancement and curtailment/settlement cost	319	499	276	2	22	-	-	-	-
Net periodic benefit cost	1,694	1,868	1,378	1,094	1,284	1,283	595	670	616
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	27	592	2,494	(156)	(1,375)	2,969	(555)	(589)	1,518
Amortization of actuarial (loss)/gain	(811)	(1,043)	(685)	(538)	(752)	(628)	(153)	(206)	(116)
Prior service cost/(credit)	-	-	(25)	32	(401)	(70)	-	(535)	-
Amortization of prior service (cost)/credit	(6)	(6)	(8)	(54)	(87)	(120)	30	24	(14)
Foreign exchange rate changes	-	-	-	(108)	(1,126)	(688)	5	(31)	(8)
Total recorded in other comprehensive income	(790)	(457)	1,776	(824)	(3,741)	1,463	(673)	(1,337)	1,380
Total recorded in net periodic benefit cost and other comprehensive income, before tax	904	1,411	3,154	270	(2,457)	2,746	(78)	(667)	1,996

Costs for defined contribution plans were $399 million, $405 million and $393 million in 2016, 2015 and 2014, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2016	2015	2014
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	790	457	(1,776)
Non-U.S. pension	824	3,741	(1,463)
Other postretirement benefits	673	1,337	(1,380)
Total (charge)/credit to other comprehensive income, before tax	2,287	5,535	(4,619)
(Charge)/credit to income tax (see Note 4)	(692)	(1,810)	1,549
(Charge)/credit to investment in equity companies	(16)	81	(81)
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	1,579	3,806	(3,151)
Charge/(credit) to equity of noncontrolling interests	24	(202)	85
(Charge)/credit to other comprehensive income attributable to ExxonMobil	1,603	3,604	(3,066)

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2016 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, 2016, Using:					Fair Value Measurement at December 31, 2016, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
					(millions of dollars)					
Asset category:										
Equity securities										
U.S.	-	-	-	2,347	2,347	-	-	-	3,343	3,343
Non-U.S.	-	-	-	2,126	2,126	142 *(2)*	2 *(3)*	-	3,632	3,776
Private equity	-	-	-	553	553	-	-	-	539	539
Debt securities										
Corporate	-	4,978 *(4)*	-	1	4,979	-	123 *(4)*	-	4,075	4,198
Government	-	2,635 *(4)*	-	1	2,636	167 *(5)*	32 *(4)*	-	6,753	6,952
Asset-backed	-	3 *(4)*	-	1	4	-	35 *(4)*	-	72	107
Real estate funds	-	-	-	-	-	-	-	-	-	-
Cash	-	-	-	137	137	23	9 *(6)*	-	73	105
Total at fair value	-	7,616	-	5,166	12,782	332	201	-	18,487	19,020
Insurance contracts at contract value					11					23
Total plan assets					12,793					19,043

(1) Per ASU 2015-07, certain instruments that are measured at fair value using the Net Asset Value (NAV) per share practical expedient have not been categorized in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the total value of plan assets.

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

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2016, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
	(millions of dollars)				
Asset category:					
Equity securities					
U.S.	-	-	-	98	98
Non-U.S.	-	-	-	71	71
Private equity	-	-	-	-	-
Debt securities					
Corporate	-	82 *(2)*	-	-	82
Government	-	159 *(2)*	-	-	159
Asset-backed	-	1 *(2)*	-	-	1
Cash	-	-	-	-	-
Total at fair value	-	242	-	169	411

(1) Per ASU 2015-07, certain instruments that are measured at fair value using the Net Asset Value (NAV) per share practical expedient have not been categorized in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the total value of plan assets.

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

The 2015 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, 2015, Using:					Fair Value Measurement at December 31, 2015, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
Asset category:										
Equity securities										
U.S.	-	-	-	1,992	1,992	-	-	-	3,179	3,179
Non-U.S.	-	-	-	1,775	1,775	179 *(2)*	3 *(3)*	-	3,426	3,608
Private equity	-	-	-	595	595	-	-	-	581	581
Debt securities										
Corporate	-	4,160 *(4)*	-	1	4,161	-	120 *(4)*	-	2,441	2,561
Government	-	2,393 *(4)*	-	1	2,394	243 *(5)*	30 *(4)*	-	8,095	8,368
Asset-backed	-	2 *(4)*	-	1	3	-	5 *(4)*	-	66	71
Real estate funds	-	-	-	-	-	-	-	-	-	-
Cash	-	-	-	50	50	-	10 *(6)*	-	13	23
Total at fair value	-	6,555	-	4,415	10,970	422	168	-	17,801	18,391
Insurance contracts at contract value					15					26
Total plan assets					10,985					18,417

(1) Per ASU 2015-07, certain instruments that are measured at fair value using the Net Asset Value (NAV) per share practical expedient have not been categorized in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the total value of plan assets.

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

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2015, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
	(millions of dollars)				
Asset category:					
Equity securities					
U.S.	-	-	-	96	96
Non-U.S.	-	-	-	67	67
Private equity	-	-	-	-	-
Debt securities					
Corporate	-	79 *(2)*	-	-	79
Government	-	170 *(2)*	-	-	170
Asset-backed	-	1 *(2)*	-	-	1
Cash	-	-	-	1	1
Total at fair value	-	250	-	164	414

(1) Per ASU 2015-07, certain instruments that are measured at fair value using the Net Asset Value (NAV) per share practical expedient have not been categorized in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the total value of plan assets.

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

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2016	2015	2016	2015
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	17,099	16,767	837	1,827
Accumulated benefit obligation	14,390	13,913	612	1,373
Fair value of plan assets	12,793	10,985	564	1,299
For unfunded pension plans:				
Projected benefit obligation	2,861	2,816	6,365	6,112
Accumulated benefit obligation	1,855	1,753	5,687	5,290

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2017 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	841	462	104
Prior service cost *(2)*	5	45	(33)

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

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

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2017	560	540	-	-
Benefit payments expected in:				
2017	1,817	1,090	459	24
2018	1,582	1,086	468	25
2019	1,484	1,123	474	26
2020	1,441	1,131	478	28
2021	1,426	1,125	480	29
2022 - 2026	6,910	5,827	2,381	168

18. Disclosures about Segments and Related Information

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

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

Earnings after income tax include transfers at estimated market prices.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense of $63 million in 2016, $100 million in 2015 and $129 million in 2014.

	Upstream		Downstream		Chemical		Corporate and Financing	Corporate Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.		
				(millions of dollars)				
As of December 31, 2016								
Earnings after income tax	(4,151)	4,347	1,094	3,107	1,876	2,739	(1,172)	7,840
Earnings of equity companies included above	53	3,359	58	404	111	1,188	(367)	4,806
Sales and other operating revenue *(1)*	7,552	12,628	55,984	116,365	9,945	16,113	21	218,608
Intersegment revenue	3,827	18,099	11,796	18,775	6,404	4,211	236	-
Depreciation and depletion expense	9,626	9,550	628	889	275	477	863	22,308
Interest revenue	-	-	-	-	-	-	30	30
Interest expense	17	29	1	8	-	-	398	453
Income taxes	(2,600)	1,818	396	951	693	609	(2,273)	(406)
Additions to property, plant and equipment	3,144	7,878	791	1,525	1,463	482	817	16,100
Investments in equity companies	4,917	11,364	111	1,255	158	3,247	(242)	20,810
Total assets	86,146	153,183	16,201	29,208	11,600	18,453	15,523	330,314
As of December 31, 2015								
Earnings after income tax	(1,079)	8,180	1,901	4,656	2,386	2,032	(1,926)	16,150
Earnings of equity companies included above	226	5,831	170	444	144	1,235	(406)	7,644
Sales and other operating revenue *(1)*	8,241	15,812	73,063	134,230	10,880	17,254	8	259,488
Intersegment revenue	4,344	20,839	12,440	22,166	7,442	5,168	274	-
Depreciation and depletion expense	5,301	9,227	664	1,003	375	654	824	18,048
Interest revenue	-	-	-	-	-	-	46	46
Interest expense	26	27	8	4	-	1	245	311
Income taxes	(879)	4,703	866	1,325	646	633	(1,879)	5,415
Additions to property, plant and equipment	6,915	14,561	916	1,477	1,865	629	1,112	27,475
Investments in equity companies	5,160	10,980	95	1,179	125	3,025	(227)	20,337
Total assets	93,648	155,316	16,498	29,808	10,174	18,236	13,078	336,758
As of December 31, 2014								
Earnings after income tax	5,197	22,351	1,618	1,427	2,804	1,511	(2,388)	32,520
Earnings of equity companies included above	1,235	10,859	29	82	186	1,377	(445)	13,323
Sales and other operating revenue *(1)*	14,826	22,336	118,771	199,976	15,115	23,063	18	394,105
Intersegment revenue	7,723	38,846	17,281	44,231	10,117	8,098	274	-
Depreciation and depletion expense	5,139	8,523	654	1,228	370	645	738	17,297
Interest revenue	-	-	-	-	-	-	75	75
Interest expense	40	17	6	4	-	-	219	286
Income taxes	1,300	15,165	610	968	1,032	358	(1,418)	18,015
Additions to property, plant and equipment	9,098	19,225	1,050	1,356	1,564	564	1,399	34,256
Investments in equity companies	5,089	10,877	69	1,006	258	3,026	(308)	20,017
Total assets	92,555	161,033	18,371	33,299	8,798	18,449	16,988	349,493

(1) Sales and other operating revenue includes sales-based taxes of $21,090 million for 2016, $22,678 million for 2015 and $29,342 million for 2014. See Note 1, Summary of Accounting Policies.

Geographic

Sales and other operating revenue *(1)*	2016	2015	2014
		(millions of dollars)	
United States	73,481	92,184	148,713
Non-U.S.	145,127	167,304	245,392
Total	218,608	259,488	394,105
Significant non-U.S. revenue sources include:			
Canada	21,130	22,876	36,072
United Kingdom	17,901	23,651	31,346
Italy	11,935	13,795	18,880
Belgium	11,464	13,154	20,953
France	10,644	11,808	17,639
Singapore	10,072	10,790	15,407
Germany	9,444	10,045	14,816

(1) Sales and other operating revenue includes sales-based taxes of $21,090 million for 2016, $22,678 million for 2015 and $29,342 million for 2014. See Note 1, Summary of Accounting Policies.

Long-lived assets	2016	2015	2014
		(millions of dollars)	
United States	101,194	107,039	104,000
Non-U.S.	143,030	144,566	148,668
Total	244,224	251,605	252,668
Significant non-U.S. long-lived assets include:			
Canada	40,144	39,775	43,858
Australia	16,510	15,894	15,328
Nigeria	11,314	12,222	12,265
Kazakhstan	10,325	9,705	9,138
Singapore	9,769	9,681	9,620
Angola	8,413	8,777	9,057
Papua New Guinea	5,719	5,985	6,099

19. Income, Sales-Based and Other Taxes

	2016			2015			2014		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
	(millions of dollars)								
Income tax expense									
Federal and non-U.S.									
Current	(214)	4,056	3,842	-	7,126	7,126	1,456	14,755	16,211
Deferred - net	(2,801)	(1,422)	(4,223)	(1,166)	(571)	(1,737)	900	1,398	2,298
U.S. tax on non-U.S. operations	41	-	41	38	-	38	5	-	5
Total federal and non-U.S.	(2,974)	2,634	(340)	(1,128)	6,555	5,427	2,361	16,153	18,514
State *(1)*	(66)	-	(66)	(12)	-	(12)	(499)	-	(499)
Total income tax expense	(3,040)	2,634	(406)	(1,140)	6,555	5,415	1,862	16,153	18,015
Sales-based taxes	6,465	14,625	21,090	6,402	16,276	22,678	6,310	23,032	29,342
All other taxes and duties									
Other taxes and duties	99	25,811	25,910	162	27,103	27,265	378	31,908	32,286
Included in production and manufacturing expenses	1,052	808	1,860	1,157	828	1,985	1,454	1,179	2,633
Included in SG&A expenses	133	362	495	150	390	540	155	441	596
Total other taxes and duties	1,284	26,981	28,265	1,469	28,321	29,790	1,987	33,528	35,515
Total	4,709	44,240	48,949	6,731	51,152	57,883	10,159	72,713	82,872

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

All other taxes and duties include taxes reported in production and manufacturing and selling, general and administrative (SG&A) expenses. The above provisions for deferred income taxes include net charges of $180 million in 2016 and $177 million in 2015 and a net credit of $40 million in 2014 for the effect of changes in tax laws and rates.

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2016, 2015 and 2014 is as follows:

	2016	2015	2014
		(millions of dollars)	
Income before income taxes			
United States	(5,832)	147	9,080
Non-U.S.	13,801	21,819	42,550
Total	7,969	21,966	51,630
Theoretical tax	2,789	7,688	18,071
Effect of equity method of accounting	(1,682)	(2,675)	(4,663)
Non-U.S. taxes in excess of/(less than) theoretical U.S. tax *(1)*	(582)	1,415	5,442
U.S. tax on non-U.S. operations	41	38	5
State taxes, net of federal tax benefit	(43)	(8)	(324)
Other *(2)*	(929)	(1,043)	(516)
Total income tax expense	(406)	5,415	18,015
Effective tax rate calculation			
Income taxes	(406)	5,415	18,015
ExxonMobil share of equity company income taxes	1,692	3,011	5,678
Total income taxes	1,286	8,426	23,693
Net income including noncontrolling interests	8,375	16,551	33,615
Total income before taxes	9,661	24,977	57,308
Effective income tax rate	13%	34%	41%

(1) 2016 includes a $227 million expense from an adjustment to deferred taxes and a $548 million benefit from an adjustment to a tax position in prior years.

(2) 2016 includes an exploration tax benefit of $198 million and benefits from an adjustment to a prior year tax position of $176 million.

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:	**2016**	**2015**
	(millions of dollars)	
Property, plant and equipment	46,744	49,409
Other liabilities	4,262	4,613
Total deferred tax liabilities	51,006	54,022
Pension and other postretirement benefits	(6,053)	(6,286)
Asset retirement obligations	(5,454)	(6,277)
Tax loss carryforwards	(5,472)	(4,983)
Other assets	(5,615)	(5,592)
Total deferred tax assets	(22,594)	(23,138)
Asset valuation allowances	1,509	1,730
Net deferred tax liabilities	29,921	32,614

In 2016, asset valuation allowances of $1,509 million decreased by $221 million and included net provisions of $180 million and effects of foreign currency translation of $41 million.

Deferred income tax (assets) and liabilities are included in the balance sheet as shown below. Effective September 30, 2016, the Corporation early-adopted Accounting Standard Update no. 2015-17 *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* on a prospective basis. This update eliminates the requirement to classify deferred tax assets and liabilities as current and noncurrent, and instead requires all deferred tax assets and liabilities to be classified as noncurrent.

Balance sheet classification	**2016**	**2015**
	(millions of dollars)	
Other current assets	-	(1,329)
Other assets, including intangibles, net	(4,120)	(3,421)
Accounts payable and accrued liabilities	-	546
Deferred income tax liabilities	34,041	36,818
Net deferred tax liabilities	29,921	32,614

The Corporation had $54 billion of indefinitely reinvested, undistributed earnings from subsidiary companies outside the U.S. that were retained to fund prior and future capital project expenditures. Deferred taxes have not been recorded for potential future tax obligations as these earnings are expected to be indefinitely reinvested for the foreseeable future. As of December 31, 2016, it is not practical to estimate the unrecognized deferred tax liability associated with these earnings given the future availability of foreign tax credits and uncertainties about the timing of potential remittances.

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	2016	2015	2014
		(millions of dollars)	
Balance at January 1	9,396	8,986	7,838
Additions based on current year's tax positions	655	903	1,454
Additions for prior years' tax positions	534	496	448
Reductions for prior years' tax positions	(1,019)	(190)	(532)
Reductions due to lapse of the statute of limitations	(7)	(4)	(117)
Settlements with tax authorities	(70)	(725)	(43)
Foreign exchange effects/other	(21)	(70)	(62)
Balance at December 31	9,468	9,396	8,986

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 2016, 2015 and 2014 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. In the United States, the Corporation has various ongoing U.S. federal income tax positions at issue with the Internal Revenue Service (IRS) for tax years beginning in 2006. The IRS has asserted penalties associated with several of those positions. The Corporation has not recognized the penalties as an expense because the Corporation does not expect the penalties to be sustained under applicable law. The Corporation has filed a refund suit for tax years 2006-2009 in a U.S. federal district court with respect to the positions at issue for those years. Unfavorable resolution of all positions at issue with the IRS would not have a materially adverse effect on the Corporation's net income or liquidity.

It is reasonably possible that the total amount of unrecognized tax benefits could change in the next 12 months in a range from a decrease of 10 percent to an increase of up to 15 percent, 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	2014 - 2016
Angola	2010 - 2016
Australia	2008 - 2016
Canada	1994 - 2016
Equatorial Guinea	2007 - 2016
Malaysia	2009 - 2016
Nigeria	2005 - 2016
Norway	2007 - 2016
Qatar	2009 - 2016
Russia	2014 - 2016
United Kingdom	2014 - 2016
United States	2006 - 2016

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 $4 million, $39 million and $42 million in interest expense on income tax reserves in 2016, 2015 and 2014, respectively. The related interest payable balances were $191 million and $223 million at December 31, 2016, and 2015, respectively.

20. Subsequent Events

The Corporation completed the acquisition of InterOil Corporation (IOC) for about $2.5 billion on February 22, 2017. IOC is an exploration and production business focused on Papua New Guinea. Consideration includes around 28 million shares of Exxon Mobil Corporation common stock with an estimated value of $2.3 billion, a Contingent Resource Payment (CRP) and cash. The CRP provides IOC shareholders $7.07 per share in cash for each incremental certified Trillion Cubic Feet Equivalent (TCFE) of resources above 6.2 TCFE, and up to 11.0 TCFE. IOC's assets include a receivable related to the same resource base for volumes in excess of 3.5 TCFE at amounts ranging from $0.24 - $0.40 per thousand cubic feet equivalent. The receivable is expected to more than cover the CRP.

On January 16, 2017, an affiliate of the Corporation entered into a Purchase and Sale Agreement with the Bass family of Fort Worth, Texas, to acquire companies that indirectly own certain oil and gas properties in the Permian Basin and certain additional properties and related assets in exchange for shares of Exxon Mobil Corporation common stock having an aggregate value at the time of closing of $5.6 billion, together with additional contingent cash payments tied to future drilling and completion activities (up to a maximum of $1.02 billion). The transaction is currently expected to close on or about February 28, 2017. As of January 16, 2017, the number of shares issuable in connection with the transaction would have been approximately 63 million.

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $719 million in 2016, $831 million in 2015, and $3,223 million in 2014. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations	**United States**	**Canada/ South America**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)			
Consolidated Subsidiaries							
2016 - Revenue							
Sales to third parties	4,424	1,511	2,921	705	1,826	1,273	12,660
Transfers	2,323	2,652	1,568	6,498	4,638	578	18,257
	6,747	4,163	4,489	7,203	6,464	1,851	30,917
Production costs excluding taxes	3,590	3,651	1,794	2,216	1,331	531	13,113
Exploration expenses	220	572	94	292	205	84	1,467
Depreciation and depletion	9,334	1,601	1,678	3,573	1,613	532	18,331
Taxes other than income	491	165	139	762	621	209	2,387
Related income tax	(2,543)	(688)	546	(149)	1,767	167	(900)
Results of producing activities for consolidated subsidiaries	(4,345)	(1,138)	238	509	927	328	(3,481)
Equity Companies							
2016 - Revenue							
Sales to third parties	506	-	1,677	-	7,208	-	9,391
Transfers	344	-	9	-	418	-	771
	850	-	1,686	-	7,626	-	10,162
Production costs excluding taxes	527	-	529	-	504	-	1,560
Exploration expenses	-	-	36	-	21	-	57
Depreciation and depletion	301	-	143	-	437	-	881
Taxes other than income	31	-	661	-	2,456	-	3,148
Related income tax	-	-	86	-	1,472	-	1,558
Results of producing activities for equity companies	(9)	-	231	-	2,736	-	2,958
Total results of operations	(4,354)	(1,138)	469	509	3,663	328	(523)

Results of Operations	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2015 - Revenue							
Sales to third parties	4,830	1,756	3,933	1,275	2,651	1,408	15,853
Transfers	2,557	2,858	2,024	8,135	4,490	608	20,672
	7,387	4,614	5,957	9,410	7,141	2,016	36,525
Production costs excluding taxes	4,252	3,690	2,232	1,993	1,562	527	14,256
Exploration expenses	182	473	187	319	254	108	1,523
Depreciation and depletion	5,054	1,315	1,641	3,874	1,569	392	13,845
Taxes other than income	630	111	200	734	706	171	2,552
Related income tax	(976)	(79)	807	1,556	2,117	238	3,663
Results of producing activities for consolidated subsidiaries	(1,755)	(896)	890	934	933	580	686
Equity Companies							
2015 - Revenue							
Sales to third parties	608	-	2,723	-	11,174	-	14,505
Transfers	459	-	31	-	379	-	869
	1,067	-	2,754	-	11,553	-	15,374
Production costs excluding taxes	554	-	565	-	422	-	1,541
Exploration expenses	12	-	21	-	18	-	51
Depreciation and depletion	271	-	146	-	457	-	874
Taxes other than income	47	-	1,258	-	3,197	-	4,502
Related income tax	-	-	263	-	2,559	-	2,822
Results of producing activities for equity companies	183	-	501	-	4,900	-	5,584
Total results of operations	(1,572)	(896)	1,391	934	5,833	580	6,270
Consolidated Subsidiaries							
2014 - Revenue							
Sales to third parties	9,453	2,841	4,608	1,943	4,383	1,374	24,602
Transfers	5,554	5,417	5,206	14,884	7,534	1,553	40,148
	15,007	8,258	9,814	16,827	11,917	2,927	64,750
Production costs excluding taxes	4,637	4,251	3,117	2,248	1,568	583	16,404
Exploration expenses	231	363	274	427	287	87	1,669
Depreciation and depletion	4,877	1,193	1,929	3,387	1,242	454	13,082
Taxes other than income	1,116	160	412	1,539	1,542	399	5,168
Related income tax	1,208	524	2,954	5,515	4,882	435	15,518
Results of producing activities for consolidated subsidiaries	2,938	1,767	1,128	3,711	2,396	969	12,909
Equity Companies							
2014 - Revenue							
Sales to third parties	1,239	-	4,923	-	20,028	-	26,190
Transfers	924	-	63	-	685	-	1,672
	2,163	-	4,986	-	20,713	-	27,862
Production costs excluding taxes	620	-	602	-	548	-	1,770
Exploration expenses	61	-	22	-	219	-	302
Depreciation and depletion	253	-	195	-	383	-	831
Taxes other than income	57	-	2,650	-	5,184	-	7,891
Related income tax	-	-	553	-	5,099	-	5,652
Results of producing activities for equity companies	1,172	-	964	-	9,280	-	11,416
Total results of operations	4,110	1,767	2,092	3,711	11,676	969	24,325

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $15,239 million less at year-end 2016 and $14,685 million less at year-end 2015 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs	United States	Canada/ South America	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2016							
Property (acreage) costs - Proved	16,075	2,339	134	929	1,739	736	21,952
- Unproved	22,747	4,030	25	291	269	115	27,477
Total property costs	38,822	6,369	159	1,220	2,008	851	49,429
Producing assets	91,651	40,291	33,811	51,307	34,690	11,730	263,480
Incomplete construction	2,099	6,154	1,403	4,495	8,377	2,827	25,355
Total capitalized costs	132,572	52,814	35,373	57,022	45,075	15,408	338,264
Accumulated depreciation and depletion	55,924	15,740	28,291	35,085	17,475	5,084	157,599
Net capitalized costs for consolidated subsidiaries	76,648	37,074	7,082	21,937	27,600	10,324	180,665
Equity Companies							
As of December 31, 2016							
Property (acreage) costs - Proved	77	-	3	-	-	-	80
- Unproved	12	-	-	-	59	-	71
Total property costs	89	-	3	-	59	-	151
Producing assets	6,326	-	5,043	-	8,646	-	20,015
Incomplete construction	109	-	40	-	4,791	-	4,940
Total capitalized costs	6,524	-	5,086	-	13,496	-	25,106
Accumulated depreciation and depletion	2,417	-	3,987	-	6,013	-	12,417
Net capitalized costs for equity companies	4,107	-	1,099	-	7,483	-	12,689
Consolidated Subsidiaries							
As of December 31, 2015							
Property (acreage) costs - Proved	15,989	2,202	143	873	1,648	741	21,596
- Unproved	23,071	4,014	44	367	409	116	28,021
Total property costs	39,060	6,216	187	1,240	2,057	857	49,617
Producing assets	84,270	38,108	36,262	49,621	32,359	9,414	250,034
Incomplete construction	6,980	5,708	1,928	4,395	8,620	4,564	32,195
Total capitalized costs	130,310	50,032	38,377	55,256	43,036	14,835	331,846
Accumulated depreciation and depletion	46,864	13,873	29,747	31,579	16,073	4,573	142,709
Net capitalized costs for consolidated subsidiaries	83,446	36,159	8,630	23,677	26,963	10,262	189,137
Equity Companies							
As of December 31, 2015							
Property (acreage) costs - Proved	78	-	4	-	-	-	82
- Unproved	14	-	-	-	59	-	73
Total property costs	92	-	4	-	59	-	155
Producing assets	6,181	-	5,089	-	8,563	-	19,833
Incomplete construction	194	-	77	-	3,727	-	3,998
Total capitalized costs	6,467	-	5,170	-	12,349	-	23,986
Accumulated depreciation and depletion	2,122	-	3,916	-	5,563	-	11,601
Net capitalized costs for equity companies	4,345	-	1,254	-	6,786	-	12,385

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2016 were $11,375 million, down $10,512 million from 2015, due primarily to lower development costs. In 2015 costs were $21,887 million, down $7,228 million from 2014, due primarily to lower development costs and property acquisition costs. Total equity company costs incurred in 2016 were $1,406 million, down $58 million from 2015, due primarily to lower development costs.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		**United States**	**Canada/ South America**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)				
During 2016								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	1	1	-	-	71	-	73
	- Unproved	170	27	-	-	-	-	197
Exploration costs		145	689	156	321	187	133	1,631
Development costs		3,054	1,396	538	1,866	2,214	406	9,474
Total costs incurred for consolidated subsidiaries		3,370	2,113	694	2,187	2,472	539	11,375
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	-	-	-
Exploration costs		1	-	36	-	32	-	69
Development costs		106	-	88	-	1,143	-	1,337
Total costs incurred for equity companies		107	-	124	-	1,175	-	1,406
During 2015								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	6	-	-	-	31	-	37
	- Unproved	305	39	-	93	1	2	440
Exploration costs		195	621	411	425	405	157	2,214
Development costs		6,774	3,764	1,439	3,149	3,068	1,002	19,196
Total costs incurred for consolidated subsidiaries		7,280	4,424	1,850	3,667	3,505	1,161	21,887
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	-	-	-
Exploration costs		9	-	41	-	(19)	-	31
Development costs		411	-	143	-	879	-	1,433
Total costs incurred for equity companies		420	-	184	-	860	-	1,464
During 2014								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	80	-	-	-	41	-	121
	- Unproved	1,253	3	19	34	-	-	1,309
Exploration costs		319	453	458	628	467	121	2,446
Development costs		7,540	6,877	1,390	4,255	3,321	1,856	25,239
Total costs incurred for consolidated subsidiaries		9,192	7,333	1,867	4,917	3,829	1,977	29,115
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	42	-	42
Exploration costs		17	-	45	-	964	-	1,026
Development costs		490	-	233	-	886	-	1,609
Total costs incurred for equity companies		507	-	278	-	1,892	-	2,677

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2014, 2015, and 2016.

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

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

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

Revisions can include upward or downward changes in previously estimated volumes of proved reserves for existing fields due to the evaluation or re-evaluation of (1) already available geologic, reservoir or production data, (2) new geologic, reservoir or production data or (3) changes in the average of first-of-month oil and natural gas prices and / or costs that are used in the estimation of reserves. Revisions can also result from significant changes in either development strategy or production equipment/facility capacity. Reserve volumes that were subject to a downward revision can be revised upward at some point in the future when price levels increase, costs decline, and / or operating efficiencies occur.

As a result of very low prices during 2016, under the SEC definition of proved reserves, certain quantities of oil and natural gas that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2016 and are reflected as downward revisions. Amounts no longer qualifying as proved reserves include the entire 3.5 billion barrels of bitumen at Kearl. In addition, 0.8 billion barrels of oil equivalent across the remainder of North America no longer qualify as proved reserves mainly due to the acceleration of the projected end-of-field-life. Among the factors that would result in these amounts being recognized again as proved reserves at some point in the future are a recovery in average price levels, a further decline in costs, and / or operating efficiencies. We do not expect the downward revision of reported proved reserves under SEC definitions to affect the operation of the underlying projects or to alter our outlook for future production volumes.

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. Natural gas reserves exclude the gaseous equivalent of liquids expected to be removed from the natural gas on leases, at field facilities and at gas processing plants. These liquids are included in net proved reserves of crude oil and natural gas liquids.

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

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The production and reserves that we report for these types of arrangements typically vary inversely with oil and natural gas price changes. As oil and natural gas prices increase, the cash flow and value received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2016 that were associated with production sharing contract arrangements was 14 percent of liquids, 9 percent of natural gas and 12 percent on an oil-equivalent basis (natural gas converted to oil-equivalent at 6 billion cubic feet = 1 million barrels).

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

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

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

	Crude Oil							Natural Gas Liquids *(1)*	Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ S. Amer.	Canada/ S. Amer.	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2014	2,008	284	245	1,193	2,163	155	6,048	1,023	3,630	579	11,280
Revisions	37	23	9	42	42	-	153	59	669	(23)	858
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	42	-	-	-	-	-	42	11	-	-	53
Sales	(24)	(11)	-	-	(1)	-	(36)	(14)	-	-	(50)
Extensions/discoveries	156	5	-	38	35	-	234	79	-	-	313
Production	(111)	(19)	(55)	(171)	(107)	(14)	(477)	(66)	(66)	(22)	(631)
December 31, 2014	2,108	282	199	1,102	2,132	141	5,964	1,092	4,233	534	11,823
Proportional interest in proved reserves of equity companies											
January 1, 2014	330	-	28	-	1,145	-	1,503	456	-	-	1,959
Revisions	19	-	1	-	41	-	61	5	-	-	66
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	1	-	-	-	-	-	1	-	-	-	1
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	-	-	-	1
Production	(23)	-	(2)	-	(86)	-	(111)	(26)	-	-	(137)
December 31, 2014	328	-	27	-	1,100	-	1,455	435	-	-	1,890
Total liquids proved reserves at December 31, 2014	2,436	282	226	1,102	3,232	141	7,419	1,527	4,233	534	13,713
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2015	2,108	282	199	1,102	2,132	141	5,964	1,092	4,233	534	11,823
Revisions	(150)	(10)	46	48	123	(4)	53	(95)	433	68	459
Improved recovery	-	-	2	-	-	-	2	-	-	-	2
Purchases	161	3	1	-	-	-	165	46	-	-	211
Sales	(9)	-	(1)	-	(2)	-	(12)	(1)	-	-	(13)
Extensions/discoveries	387	2	-	-	698	-	1,087	101	-	-	1,188
Production	(119)	(17)	(63)	(187)	(126)	(12)	(524)	(65)	(106)	(21)	(716)
December 31, 2015	2,378	260	184	963	2,825	125	6,735	1,078	4,560	581	12,954
Proportional interest in proved reserves of equity companies											
January 1, 2015	328	-	27	-	1,100	-	1,455	435	-	-	1,890
Revisions	(52)	-	(1)	-	65	-	12	5	-	-	17
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(22)	-	(1)	-	(88)	-	(111)	(26)	-	-	(137)
December 31, 2015	254	-	25	-	1,077	-	1,356	414	-	-	1,770
Total liquids proved reserves at December 31, 2015	2,632	260	209	963	3,902	125	8,091	1,492	4,560	581	14,724

(See footnote on next page)

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

	Crude Oil							Natural Gas Liquids *(1)*	Bitumen	Synthetic Oil	
	United States	Canada/ S. Amer.	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ S. Amer.	Canada/ S. Amer.	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2016	2,378	260	184	963	2,825	125	6,735	1,078	4,560	581	12,954
Revisions	(307)	3	43	49	73	9	(130)	47	(3,748)	8	(3,823)
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	79	-	-	-	-	-	79	32	-	-	111
Sales	(15)	(5)	(3)	-	-	-	(23)	(5)	-	-	(28)
Extensions/discoveries	173	3	12	-	-	-	188	66	-	-	254
Production	(127)	(20)	(63)	(168)	(140)	(13)	(531)	(64)	(111)	(25)	(731)
December 31, 2016	2,181	241	173	844	2,758	121	6,318	1,154	701	564	8,737
Proportional interest in proved reserves of equity companies											
January 1, 2016	254	-	25	-	1,077	-	1,356	414	-	-	1,770
Revisions	3	-	(7)	-	191	-	187	(5)	-	-	182
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(21)	-	(1)	-	(85)	-	(107)	(25)	-	-	(132)
December 31, 2016	236	-	17	-	1,183	-	1,436	384	-	-	1,820
Total liquids proved reserves at December 31, 2016	2,417	241	190	844	3,941	121	7,754	1,538	701	564	10,557

(1) Includes total proved reserves attributable to Imperial Oil Limited of 8 million barrels in 2014, 7 million barrels in 2015 and 7 million barrels in 2016, as well as proved developed reserves of 5 million barrels in 2014, 4 million barrels in 2015 and 4 million barrels in 2016, and in addition, proved undeveloped reserves of 3 million barrels in 2014, 3 million barrels in 2015 and 3 million in 2016, in which there is a 30.4 percent noncontrolling interest.

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ South Amer. *(2)*	Canada/ South Amer. *(3)*	Total
					(millions of barrels)					
Proved developed reserves, as of December 31, 2014										
Consolidated subsidiaries	1,502	111	205	894	1,615	112	4,439	2,122	534	7,095
Equity companies	269	-	26	-	1,188	-	1,483	-	-	1,483
Proved undeveloped reserves, as of December 31, 2014										
Consolidated subsidiaries	1,234	190	42	401	651	99	2,617	2,111	-	4,728
Equity companies	75	-	1	-	331	-	407	-	-	407
Total liquids proved reserves at December 31, 2014	3,080	301	274	1,295	3,785	211	8,946	4,233	534	13,713
Proved developed reserves, as of December 31, 2015										
Consolidated subsidiaries	1,427	101	192	900	1,707	107	4,434	4,108	581	9,123
Equity companies	228	-	25	-	1,151	-	1,404	-	-	1,404
Proved undeveloped reserves, as of December 31, 2015										
Consolidated subsidiaries	1,619	174	34	230	1,239	83	3,379	452	-	3,831
Equity companies	39	-	-	-	327	-	366	-	-	366
Total liquids proved reserves at December 31, 2015	3,313	275	251	1,130	4,424	190	9,583	4,560	581	14,724
Proved developed reserves, as of December 31, 2016										
Consolidated subsidiaries	1,317	87	175	836	1,858	105	4,378	436	564	5,378
Equity companies	210	-	11	-	1,114	-	1,335	-	-	1,335
Proved undeveloped reserves, as of December 31, 2016										
Consolidated subsidiaries	1,626	169	31	169	1,025	74	3,094	265	-	3,359
Equity companies	36	-	6	-	443	-	485	-	-	485
Total liquids proved reserves at December 31, 2016	3,189	256	223	1,005	4,440	179	9,292 *(4)*	701	564	10,557

(1) Includes total proved reserves attributable to Imperial Oil Limited of 46 million barrels in 2014, 34 million barrels in 2015 and 35 million barrels in 2016, as well as proved developed reserves of 36 million barrels in 2014, 23 million barrels in 2015 and 19 million barrels in 2016, and in addition, proved undeveloped reserves of 10 million barrels in 2014, 11 million barrels in 2015 and 16 million barrels in 2016, in which there is a 30.4 percent noncontrolling interest.

(2) Includes total proved reserves attributable to Imperial Oil Limited of 3,274 million barrels in 2014, 3,515 million barrels in 2015 and 701 million barrels in 2016, as well as proved developed reserves of 1,635 million barrels in 2014, 3,063 million barrels in 2015 and 436 million barrels in 2016, and in addition, proved undeveloped reserves of 1,639 million barrels in 2014, 452 million barrels in 2015 and 265 million barrels in 2016, in which there is a 30.4 percent noncontrolling interest.

(3) Includes total proved reserves attributable to Imperial Oil Limited of 534 million barrels in 2014, 581 million barrels in 2015 and 564 million barrels in 2016, as well as proved developed reserves of 534 million barrels in 2014, 581 million barrels in 2015 and 564 million barrels in 2016, 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 2016 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent Total
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**All Products *(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2014	26,020	1,235	2,810	867	5,734	7,515	44,181	18,644
Revisions	49	80	49	(21)	173	(38)	292	906
Improved recovery	-	-	-	-	-	-	-	-
Purchases	60	-	-	-	-	-	60	63
Sales	(314)	(48)	-	-	(3)	-	(365)	(111)
Extensions/discoveries	1,518	91	-	7	4	-	1,620	583
Production	(1,346)	(132)	(476)	(42)	(448)	(201)	(2,645)	(1,072)
December 31, 2014	25,987	1,226	2,383	811	5,460	7,276	43,143	19,013
Proportional interest in proved reserves of equity companies								
January 1, 2014	281	-	8,884	-	18,514	-	27,679	6,572
Revisions	5	-	117	-	110	-	232	105
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	1
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	1
Production	(15)	-	(583)	-	(1,119)	-	(1,717)	(423)
December 31, 2014	272	-	8,418	-	17,505	-	26,195	6,256
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,269
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2015	25,987	1,226	2,383	811	5,460	7,276	43,143	19,013
Revisions	(6,693)	(45)	63	25	303	23	(6,324)	(595)
Improved recovery	-	-	-	-	-	-	-	2
Purchases	182	29	-	-	-	-	211	246
Sales	(9)	(5)	(56)	-	(89)	-	(159)	(39)
Extensions/discoveries	1,167	34	-	-	102	-	1,303	1,405
Production	(1,254)	(112)	(434)	(43)	(447)	(258)	(2,548)	(1,140)
December 31, 2015	19,380	1,127	1,956	793	5,329	7,041	35,626	18,892
Proportional interest in proved reserves of equity companies								
January 1, 2015	272	-	8,418	-	17,505	-	26,195	6,256
Revisions	(38)	-	(83)	-	86	-	(35)	11
Improved recovery	-	-	-	-	-	-	-	-
Purchases	1	-	-	-	-	-	1	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-
Production	(15)	-	(432)	-	(1,130)	-	(1,577)	(400)
December 31, 2015	220	-	7,903	-	16,461	-	24,584	5,867
Total proved reserves at December 31, 2015	19,600	1,127	9,859	793	21,790	7,041	60,210	24,759

(See footnotes on next page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2016	19,380	1,127	1,956	793	5,329	7,041	35,626	18,892
Revisions	(1,630)	(102)	126	21	(16)	658	(943)	(3,980)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	148	-	-	-	-	-	148	135
Sales	(45)	(12)	(2)	-	-	-	(59)	(38)
Extensions/discoveries	1,156	34	6	-	-	-	1,196	453
Production	(1,223)	(107)	(427)	(43)	(392)	(342)	(2,534)	(1,153)
December 31, 2016	17,786	940	1,659	771	4,921	7,357	33,434	14,309
Proportional interest in proved reserves of equity companies								
January 1, 2016	220	-	7,903	-	16,461	-	24,584	5,867
Revisions	4	-	114	-	(183)	-	(65)	171
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	5	-	-	-	5	1
Production	(13)	-	(398)	-	(1,044)	-	(1,455)	(374)
December 31, 2016	211	-	7,624	-	15,234	-	23,069	5,665
Total proved reserves at December 31, 2016	17,997	940	9,283	771	20,155	7,357	56,503	19,974

(1) Includes total proved reserves attributable to Imperial Oil Limited of 627 billion cubic feet in 2014, 583 billion cubic feet in 2015 and 495 billion cubic feet in 2016, as well as proved developed reserves of 300 billion cubic feet in 2014, 283 billion cubic feet in 2015 and 263 billion cubic feet in 2016, and in addition, proved undeveloped reserves of 327 billion cubic feet in 2014, 300 billion cubic feet in 2015 and 232 billion cubic feet in 2016, in which there is a 30.4 percent noncontrolling interest.

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent
	United States	Canada/ South Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Total All Products** ***(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Proved developed reserves, as of December 31, 2014								
Consolidated subsidiaries	14,169	615	1,870	764	5,031	2,179	24,628	11,199
Equity companies	194	-	6,484	-	16,305	-	22,983	5,314
Proved undeveloped reserves, as of December 31, 2014								
Consolidated subsidiaries	11,818	611	513	47	429	5,097	18,515	7,814
Equity companies	78	-	1,934	-	1,200	-	3,212	942
Total proved reserves at December 31, 2014	26,259	1,226	10,801	811	22,965	7,276	69,338	25,269
Proved developed reserves, as of December 31, 2015								
Consolidated subsidiaries	13,353	552	1,593	750	4,917	1,962	23,127	12,977
Equity companies	156	-	6,146	-	15,233	-	21,535	4,993
Proved undeveloped reserves, as of December 31, 2015								
Consolidated subsidiaries	6,027	575	363	43	412	5,079	12,499	5,915
Equity companies	64	-	1,757	-	1,228	-	3,049	874
Total proved reserves at December 31, 2015	19,600	1,127	9,859	793	21,790	7,041	60,210	24,759
Proved developed reserves, as of December 31, 2016								
Consolidated subsidiaries	11,927	478	1,473	728	4,532	3,071	22,209	9,079
Equity companies	144	-	5,804	-	14,067	-	20,015	4,671
Proved undeveloped reserves, as of December 31, 2016								
Consolidated subsidiaries	5,859	462	186	43	389	4,286	11,225	5,230
Equity companies	67	-	1,820	-	1,167	-	3,054	994
Total proved reserves at December 31, 2016	17,997	940	9,283	771	20,155	7,357	56,503	19,974

(See footnotes on previous page)

Standardized Measure of Discounted Future Cash Flows

As required by the Financial Accounting Standards Board, the standardized measure of discounted future net cash flows is computed by applying first-day-of-the-month average 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 and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

Standardized Measure of Discounted Future Cash Flows	**United States**	**Canada/ South America** *(1)*	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2014							
Future cash inflows from sales of oil and gas	283,767	354,223	42,882	125,125	224,885	78,365	1,109,247
Future production costs	116,929	140,368	14,358	27,917	57,562	20,467	377,601
Future development costs	42,276	48,525	13,000	14,603	12,591	8,956	139,951
Future income tax expenses	49,807	36,787	10,651	44,977	102,581	15,050	259,853
Future net cash flows	74,755	128,543	4,873	37,628	52,151	33,892	331,842
Effect of discounting net cash flows at 10%	44,101	87,799	(52)	13,831	30,173	17,326	193,178
Discounted future net cash flows	30,654	40,744	4,925	23,797	21,978	16,566	138,664
Equity Companies							
As of December 31, 2014							
Future cash inflows from sales of oil and gas	31,924	-	71,031	-	286,124	-	389,079
Future production costs	8,895	-	50,826	-	99,193	-	158,914
Future development costs	3,386	-	2,761	-	11,260	-	17,407
Future income tax expenses	-	-	6,374	-	59,409	-	65,783
Future net cash flows	19,643	-	11,070	-	116,262	-	146,975
Effect of discounting net cash flows at 10%	10,970	-	5,534	-	61,550	-	78,054
Discounted future net cash flows	8,673	-	5,536	-	54,712	-	68,921
Total consolidated and equity interests in standardized measure of discounted future net cash flows	39,327	40,744	10,461	23,797	76,690	16,566	207,585

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

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ South America *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2015							
Future cash inflows from sales of oil and gas	144,910	176,452	23,330	57,702	156,378	29,535	588,307
Future production costs	82,678	115,285	8,735	17,114	50,745	8,889	283,446
Future development costs	35,016	36,923	11,332	11,170	15,371	8,237	118,049
Future income tax expenses	5,950	3,042	1,780	14,018	62,353	5,012	92,155
Future net cash flows	21,266	21,202	1,483	15,400	27,909	7,397	94,657
Effect of discounting net cash flows at 10%	13,336	13,415	(945)	5,226	17,396	3,454	51,882
Discounted future net cash flows	7,930	7,787	2,428	10,174	10,513	3,943	42,775
Equity Companies							
As of December 31, 2015							
Future cash inflows from sales of oil and gas	13,065	-	49,061	-	143,692	-	205,818
Future production costs	6,137	-	35,409	-	57,080	-	98,626
Future development costs	2,903	-	2,190	-	12,796	-	17,889
Future income tax expenses	-	-	4,027	-	24,855	-	28,882
Future net cash flows	4,025	-	7,435	-	48,961	-	60,421
Effect of discounting net cash flows at 10%	1,936	-	4,287	-	26,171	-	32,394
Discounted future net cash flows	2,089	-	3,148	-	22,790	-	28,027
Total consolidated and equity interests in standardized measure of discounted future net cash flows	10,019	7,787	5,576	10,174	33,303	3,943	70,802
Consolidated Subsidiaries							
As of December 31, 2016							
Future cash inflows from sales of oil and gas	118,283	50,243	15,487	40,734	118,997	28,877	372,621
Future production costs	65,585	29,798	5,362	14,447	38,727	7,643	161,562
Future development costs	31,744	11,735	9,235	8,833	13,088	8,177	82,812
Future income tax expenses	2,223	1,052	178	8,025	44,641	2,316	58,435
Future net cash flows	18,731	7,658	712	9,429	22,541	10,741	69,812
Effect of discounting net cash flows at 10%	11,039	3,443	(1,014)	2,790	12,848	5,556	34,662
Discounted future net cash flows	7,692	4,215	1,726	6,639	9,693	5,185	35,150
Equity Companies							
As of December 31, 2016							
Future cash inflows from sales of oil and gas	9,551	-	32,121	-	104,700	-	146,372
Future production costs	5,289	-	21,342	-	41,563	-	68,194
Future development costs	2,948	-	2,048	-	12,656	-	17,652
Future income tax expenses	-	-	2,206	-	16,622	-	18,828
Future net cash flows	1,314	-	6,525	-	33,859	-	41,698
Effect of discounting net cash flows at 10%	393	-	4,158	-	18,946	-	23,497
Discounted future net cash flows	921	-	2,367	-	14,913	-	18,201
Total consolidated and equity interests in standardized measure of discounted future net cash flows	8,613	4,215	4,093	6,639	24,606	5,185	53,351

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $5,607 million in 2015 and $2,322 million in 2016, in which there is a 30.4 percent noncontrolling interest.

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

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

Consolidated and Equity Interests		**2015**	
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2014	138,664	68,921	207,585
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	5,678	-	5,678
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	(20,694)	(9,492)	(30,186)
Development costs incurred during the year	18,359	1,198	19,557
Net change in prices, lifting and development costs	(203,224)	(57,478)	(260,702)
Revisions of previous reserves estimates	6,888	(134)	6,754
Accretion of discount	17,828	7,257	25,085
Net change in income taxes	79,276	17,755	97,031
Total change in the standardized measure during the year	(95,889)	(40,894)	(136,783)
Discounted future net cash flows as of December 31, 2015	42,775	28,027	70,802

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

Consolidated and Equity Interests (continued)	2016		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2015	42,775	28,027	70,802
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	1,377	5	1,382
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	(17,110)	(5,540)	(22,650)
Development costs incurred during the year	9,905	1,438	11,343
Net change in prices, lifting and development costs *(1)*	(26,561)	(15,549)	(42,110)
Revisions of previous reserves estimates	4,908	1,425	6,333
Accretion of discount	7,854	3,857	11,711
Net change in income taxes	12,002	4,538	16,540
Total change in the standardized measure during the year	(7,625)	(9,826)	(17,451)
Discounted future net cash flows as of December 31, 2016	35,150	18,201	53,351

(1) Securities and Exchange Commission (SEC) rules require the Corporation's reserves to be calculated on the basis of average first-of-month oil and natural gas prices during the reporting year. As a result of very low prices during 2016, under the SEC definition of proved reserves, certain quantities of oil and natural gas that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2016. Future net cash flows for these quantities are excluded from the 2016 Standardized Measure of Discounted Future Cash Flows. Substantially all of this reduction in discounted future net cash flows since December 31, 2015, is reflected in the line "Net change in prices, lifting and development costs" in the table above.

OPERATING INFORMATION (unaudited)

	2016	2015	2014	2013	2012
Production of crude oil, natural gas liquids, bitumen and synthetic oil					
Net production	*(thousands of barrels daily)*				
United States	494	476	454	431	418
Canada/South America	430	402	301	280	251
Europe	204	204	184	190	207
Africa	474	529	489	469	487
Asia	707	684	624	784	772
Australia/Oceania	56	50	59	48	50
Worldwide	2,365	2,345	2,111	2,202	2,185
Natural gas production available for sale					
Net production	*(millions of cubic feet daily)*				
United States	3,078	3,147	3,404	3,545	3,822
Canada/South America	239	261	310	354	362
Europe	2,173	2,286	2,816	3,251	3,220
Africa	7	5	4	6	17
Asia	3,743	4,139	4,099	4,329	4,538
Australia/Oceania	887	677	512	351	363
Worldwide	10,127	10,515	11,145	11,836	12,322
	(thousands of oil-equivalent barrels daily)				
Oil-equivalent production *(1)*	4,053	4,097	3,969	4,175	4,239
Refinery throughput	*(thousands of barrels daily)*				
United States	1,591	1,709	1,809	1,819	1,816
Canada	363	386	394	426	435
Europe	1,417	1,496	1,454	1,400	1,504
Asia Pacific	708	647	628	779	998
Other Non-U.S.	190	194	191	161	261
Worldwide	4,269	4,432	4,476	4,585	5,014
Petroleum product sales *(2)*					
United States	2,250	2,521	2,655	2,609	2,569
Canada	491	488	496	464	453
Europe	1,519	1,542	1,555	1,497	1,571
Asia Pacific and other Eastern Hemisphere	1,140	1,124	1,085	1,206	1,381
Latin America	82	79	84	111	200
Worldwide	5,482	5,754	5,875	5,887	6,174
Gasoline, naphthas	2,270	2,363	2,452	2,418	2,489
Heating oils, kerosene, diesel oils	1,772	1,924	1,912	1,838	1,947
Aviation fuels	399	413	423	462	473
Heavy fuels	370	377	390	431	515
Specialty petroleum products	671	677	698	738	750
Worldwide	5,482	5,754	5,875	5,887	6,174
Chemical prime product sales *(2)(3)*	*(thousands of metric tons)*				
United States	9,576	9,664	9,528	9,679	9,381
Non-U.S.	15,349	15,049	14,707	14,384	14,776
Worldwide	24,925	24,713	24,235	24,063	24,157

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

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

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

(3) Prime product sales are total product sales excluding carbon black oil and sulfur. Prime product sales include ExxonMobil's share of equity company volumes and finished-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/ DARREN W. WOODS
(Darren W. Woods,
Chairman of the Board)

Dated February 22, 2017

POWER OF ATTORNEY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated and on February 22, 2017.

/s/ DARREN W. WOODS (Darren W. Woods)	Chairman of the Board (Principal Executive Officer)
/s/ SUSAN K. AVERY (Susan K. Avery)	Director
/s/ MICHAEL J. BOSKIN (Michael J. Boskin)	Director
/s/ PETER BRABECK-LETMATHE (Peter Brabeck-Letmathe)	Director
/s/ ANGELA F. BRALY (Angela F. Braly)	Director

/s/ URSULA M. BURNS (Ursula M. Burns)	Director
/s/ LARRY R. FAULKNER (Larry R. Faulkner)	Director
/s/ HENRIETTA H. FORE (Henrietta H. Fore)	Director
/s/ KENNETH C. FRAZIER (Kenneth C. Frazier)	Director
/s/ DOUGLAS R. OBERHELMAN (Douglas R. Oberhelman)	Director
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director
/s/ STEVEN S REINEMUND (Steven S Reinemund)	Director
/s/ WILLIAM C. WELDON (William C. Weldon)	Director
/s/ ANDREW P. SWIGER (Andrew P. Swiger)	Senior Vice President (Principal Financial Officer)
/s/ DAVID S. ROSENTHAL (David S. Rosenthal)	Vice President and Controller (Principal Accounting Officer)

INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the Registrant's Annual Report on Form 10-K for 2015).
3(ii)	By-Laws, as revised effective November 1, 2016 (incorporated by reference to Exhibit 3(ii) to the Registrant's Report on Form 8-K of November 1, 2016).
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.*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements – Settlement in Shares.*
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 (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant's Annual Report on Form 10-K for 2014).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant's Annual Report on Form 10-K for 2014).*
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.*
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.*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors (incorporated by reference to Exhibit 10(iii)(f.3) to the Registrant's Annual Report on Form 10-K for 2014).*
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 Annual Report on Form 10-K for 2015).*
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.
32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.
32.2	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Financial Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
101	Interactive data files.

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

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

EXHIBIT 12

EXXON MOBIL CORPORATION

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
	(millions of dollars)				
Income from continuing operations attributable to ExxonMobil	7,840	16,150	32,520	32,580	44,880
Excess/(shortfall) of dividends over earnings of affiliates					
accounted for by the equity method	(579)	(691)	(358)	3	(1,157)
Provision for income taxes	(406)	5,415	18,015	24,263	31,045
Capitalized interest	(224)	(7)	121	148	(67)
Noncontrolling interests in earnings of consolidated subsidiaries	535	401	1,095	868	2,801
	7,166	21,268	51,393	57,862	77,502
Fixed Charges:					
Interest expense - borrowings	390	211	157	137	117
Capitalized interest	708	482	344	309	506
Rental cost representative of interest factor	433	585	618	612	640
	1,531	1,278	1,119	1,058	1,263
Total adjusted earnings available for payment of fixed charges	8,697	22,546	52,512	58,920	78,765
Number of times fixed charges are earned	5.7	17.6	46.9	55.7	62.4

EXHIBIT 31.1

Certification by Darren W. Woods
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Darren W. Woods, certify that:

1. I have reviewed this annual report on Form 10-K of Exxon Mobil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2017

/s/ DARREN W. WOODS
Darren W. Woods
Chief Executive Officer

EXHIBIT 31.2

Certification by Andrew P. Swiger
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, Andrew P. Swiger, certify that:

1. I have reviewed this annual report on Form 10-K of Exxon Mobil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2017

/s/ ANDREW P. SWIGER
Andrew P. Swiger
Senior Vice President
(Principal Financial Officer)

EXHIBIT 31.3

Certification by David S. Rosenthal
Pursuant to Securities Exchange Act Rule 13a-14(a)

I, David S. Rosenthal, certify that:

1. I have reviewed this annual report on Form 10-K of Exxon Mobil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2017

/s/ DAVID S. ROSENTHAL
David S. Rosenthal
Vice President and Controller
(Principal Accounting Officer)

EXHIBIT 32.1

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Darren W. Woods, the chief executive officer of Exxon Mobil Corporation (the “Company”), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the “Report”) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 22, 2017

/s/ DARREN W. WOODS
Darren W. Woods
Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Andrew P. Swiger, the principal financial officer of Exxon Mobil Corporation (the "Company"), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 22, 2017

/s/ ANDREW P. SWIGER
Andrew P. Swiger
Senior Vice President
(Principal Financial Officer)

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.3

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, David S. Rosenthal, the principal accounting officer of Exxon Mobil Corporation (the “Company”), hereby certifies that, to his knowledge:

(i) the Annual Report on Form 10-K of the Company for the year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the “Report”) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 22, 2017

/s/ DAVID S. ROSENTHAL
David S. Rosenthal
Vice President and Controller
(Principal Accounting Officer)

A signed original of this written statement required by Section 906 has been provided to Exxon Mobil Corporation and will be retained by Exxon Mobil Corporation and furnished to the Securities and Exchange Commission or its staff upon request.