EXXON MOBIL CORP
Form 10-K
February 22, 2017

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 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
	162	7	265	-	462	511

Canada/South America *(1)*						
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

During 2014	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
	(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, 2		