

EXXON MOBIL CORP  
Form 10-K  
February 27, 2019

2018

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, 2018

or

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

For the transition period from to

Commission File Number 1-2256

**EXXON MOBIL CORPORATION**

(Exact name of registrant as specified in its charter)

**NEW JERSEY**  
(State or other jurisdiction of

**13-5409005**  
(I.R.S. Employer

incorporation or organization)

Identification Number)

**5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298**

(Address of principal executive offices) (Zip Code)

(972) 940-6000

(Registrant's telephone number, including area code)

--	--	--

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

	Name of Each Exchange
Title of Each Class	on Which Registered
<b>Common Stock, without par value (4,234,802,431 shares outstanding at January 31, 2019)</b>	<b>New York Stock Exchange</b>

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 every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) 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 (§ 229.405 of this chapter) 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company
	Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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 29, 2018, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of \$82.73 on the New York Stock Exchange composite tape, was in excess of \$350 billion.

**Documents Incorporated by Reference: Proxy Statement for the 2019 Annual Meeting of Shareholders (Part III)**

**EXXON MOBIL CORPORATION**  
**FORM 10-K**  
**FOR THE FISCAL YEAR ENDED DECEMBER 31, 2018**  
**TABLE OF CONTENTS**

**PART I**

Item 1.	Business	1
Item 1A.	Risk Factors	2
Item 1B.	Unresolved Staff Comments	5
Item 2.	Properties	6
Item 3.	Legal Proceedings	27
Item 4.	Mine Safety Disclosures	27
Executive Officers of the Registrant [pursuant to Instruction 3 to Regulation S-K, Item 401(b)]		28

**PART II**

Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	31
Item 6.	Selected Financial Data	31
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	31
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	31
Item 8.	Financial Statements and Supplementary Data	32
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	32
Item 9A.	Controls and Procedures	32

Item 9B.	Other Information	32
<b>PART III</b>		
Item 10.	Directors, Executive Officers and Corporate Governance	33
Item 11.	Executive Compensation	33
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	33
Item 13.	Certain Relationships and Related Transactions, and Director Independence	34
Item 14.	Principal Accounting Fees and Services	34
<b>PART IV</b>		
Item 15.	Exhibits, Financial Statement Schedules	34
Item 16.	Form 10-K Summary	34
Financial Section		35
Index to Exhibits		123
Signatures		124
Exhibits 31 and 32 — Certifications		

---

## 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 involves exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals 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.

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. ExxonMobil held nearly 13 thousand active patents worldwide at the end of 2018. For technology licensed to third parties, revenues totaled approximately \$119 million in 2018. 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 71.0 thousand, 69.6 thousand, and 71.1 thousand at years ended 2018, 2017 and 2016, 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.

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 2018 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil’s share of equity company expenditures, were \$4.9 billion, of which \$3.6 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately \$5.7 billion in 2019 and 2020. Capital expenditures are expected to account for approximately 30 percent of the total.

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](http://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.

The SEC maintains an internet site (<http://www.sec.gov>) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

## 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 is generally linked closely with broad-based economic activities and levels of prosperity. 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; increased competitiveness of alternative energy sources; changes in technology or consumer preferences that alter fuel choices, such as technological advances in energy storage that make wind and solar more competitive for power generation or increased consumer demand for alternative fueled or electric vehicles; and broad-based changes in personal income levels.

**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 relative to demand 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 countries to OPEC production quotas and other agreements among sovereigns, and the occurrence of wars, hostile actions, natural disasters, disruptions in competitors' operations, logistics constraints 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.

### **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 United States 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, or may be unable to maintain, 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 or interpretation of settled 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, hydraulic fracturing or plastics);
•	adoption of regulations mandating efficiency standards, 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, cybersecurity attacks, 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 risks 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, minimum renewable usage requirements, restrictive permitting, increased efficiency standards, and incentives or mandates for renewable energy. Such policies could make our products more expensive, less competitive, 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 or policies 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<sub>2</sub> 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 “Operational and Other Factors” below.

### **Operational and Other Factors**

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 and portfolio management.** The long-term 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. In addition to the effective management of individual projects, ExxonMobil's success, including our ability to mitigate risk and provide attractive returns to shareholders, depends on our ability to successfully manage our overall portfolio, including diversification among types and locations of our projects.

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 and technological change.** 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. To remain competitive we must also continuously adapt and capture the benefits of new and emerging technologies.

**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 on workplace safety and 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.

**Cybersecurity.** ExxonMobil is regularly subject to attempted cybersecurity disruptions from a variety of threat actors including state-sponsored actors. ExxonMobil's defensive preparedness includes multi-layered technological capabilities for prevention and detection of cybersecurity disruptions; non-technological measures such as threat information sharing with governmental and industry groups; internal training and awareness campaigns including routine testing of employee awareness and an emphasis on resiliency including business response and recovery. If the measures we are taking to protect against cybersecurity disruptions prove to be insufficient, ExxonMobil as well as our customers, employees, or third parties could be adversely affected. Cybersecurity disruptions could cause physical harm to people or the environment; damage or destroy assets; compromise business systems; result in proprietary information being altered, lost, or stolen; result in employee, customer, or third-party information being compromised; or otherwise disrupt our business operations. We could incur significant costs to remedy the effects of a major

cybersecurity disruption in addition to costs in connection with resulting regulatory actions, litigation or reputational harm.

**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 rainfall 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.

**Insurance limitations.** The ability of the Corporation to insure against many of the risks it faces as described in this Item 1A is limited by the capacity of the applicable insurance markets, which may not be sufficient.

**Competition.** As noted in Item 1 above, the energy and petrochemical industries are highly competitive. We face competition not only from other private firms, but also from state-owned companies that are increasingly competing for opportunities outside of their home countries. In some cases, these state-owned companies may pursue opportunities in furtherance of strategic objectives of their government owners, with less focus on financial returns than companies owned by private shareholders, such as ExxonMobil. Technology and expertise provided by industry service companies may also enhance the competitiveness of firms that may not have the internal resources and capabilities of ExxonMobil or reduce the need for resource-owning countries to partner with private-sector oil and gas companies in order to monetize national resources.

**Reputation.** Our reputation is an important corporate asset. An operating incident, significant cybersecurity disruption, or other adverse event such as those described in this Item 1A may have a negative impact on our reputation, which in turn could make it more difficult for us to compete successfully for new opportunities, obtain necessary regulatory approvals, or could reduce consumer demand for our branded products. ExxonMobil's reputation may also be harmed by events which negatively affect the image of our industry as a whole.

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**

None.

**Item 2. Properties**

Information with regard to oil and gas producing activities follows:

**1. Disclosure of Reserves****A. Summary of Oil and Gas Reserves at Year-End 2018**

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and equity companies. Natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million 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. No major discovery or other favorable or adverse event has occurred since December 31, 2018, that would cause a significant change in the estimated proved reserves as of that date.

	<b>Crude Oil</b>	<b>Natural Gas Liquids</b>	<b>Bitumen</b>	<b>Synthetic Oil</b>	<b>Natural Gas</b>	<b>Oil-Equivalent Total All Products</b>
	<i>(million bbls)</i>	<i>(million bbls)</i>	<i>(million bbls)</i>	<i>(million bbls)</i>	<i>(billion cubic ft)</i>	<i>(million bbls)</i>
<b>Proved Reserves</b>						
<b>Developed</b>						
<b>Consolidated Subsidiaries</b>						
United States	1,257	439	-	-	12,538	3,786
Canada/Other Americas (1)	144	9	3,880	466	605	4,599
Europe	101	22	-	-	1,116	309
Africa	496	82	-	-	581	675
Asia	2,184	101	-	-	3,618	2,888
Australia/Oceania	75	43	-	-	4,336	841
Total Consolidated	4,257	696	3,880	466	22,794	13,098
<b>Equity Companies</b>						
United States	202	6	-	-	152	233
Europe	15	-	-	-	988	180
Africa	-	-	-	-	-	-
Asia	637	282	-	-	11,951	2,911
Total Equity Company	854	288	-	-	13,091	3,324
Total Developed	5,111	984	3,880	466	35,885	16,422
<b>Undeveloped</b>						
<b>Consolidated Subsidiaries</b>						
United States	1,947	669	-	-	8,865	4,093
	385	18	305	-	1,139	898

Canada/Other Americas (1)						
Europe	65	13	-	-	196	111
Africa	108	3	-	-	7	112
Asia	1,173	-	-	-	223	1,210
Australia/Oceania	30	5	-	-	3,126	556
Total Consolidated	3,708	708	305	-	13,556	6,980
<b>Equity Companies</b>						
United States	52	4	-	-	73	68
Europe	-	-	-	-	69	12
Africa	6	-	-	-	863	150
Asia	383	50	-	-	1,370	661
Total Equity Company	441	54	-	-	2,375	891
Total Undeveloped	4,149	762	305	-	15,931	7,871
<b>Total Proved Reserves</b>	<b>9,260</b>	<b>1,746</b>	<b>4,185</b>	<b>466</b>	<b>51,816</b>	<b>24,293</b>

(1) Other Americas includes proved developed reserves of 1 million barrels of crude oil and 99 billion cubic feet of natural gas, as well as proved undeveloped reserves of 226 million barrels of crude oil and 423 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, government policies, consumer preferences, and significant changes in 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.

#### **B. Technologies Used in Establishing Proved Reserves Additions in 2018**

Additions to ExxonMobil's proved reserves in 2018 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 oil, 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, has a degree in Engineering and currently serves on the Oil and Gas Reserves Committee 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.

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 2018, approximately 7.9 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 32 percent of the 24.3 GOEB reported in proved reserves. This compares to the 7.3 GOEB of proved undeveloped reserves reported at the end of 2017. During the year, ExxonMobil conducted development activities that resulted in the transfer of approximately 0.8 GOEB from proved undeveloped to proved developed reserves by year end. The largest transfers were related to drilling activity in the United States, the United Arab Emirates, Canada, and Russia. During 2018, extensions and discoveries, primarily in the United States resulted in an addition of approximately 1.7 GOEB of proved undeveloped reserves. Also, the Corporation reclassified approximately 0.3 GOEB of proved undeveloped reserves which no longer met the SEC definition of proved reserves, primarily in the Netherlands at the Groningen gas field and the United States.

Overall, investments of \$13.2 billion were made by the Corporation during 2018 to progress the development of reported proved undeveloped reserves, including \$13.1 billion for oil and gas producing activities and additional investments for other non-oil and gas producing activities such as the construction of support infrastructure and other related facilities. These investments represented 65 percent of the \$20.2 billion in total reported Upstream capital and exploration expenditures.

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 and can exceed five years for large and complex projects. Proved undeveloped reserves in the United States, Canada, Australia, and Kazakhstan have remained undeveloped for five years or more primarily due to constraints on the capacity of infrastructure, 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, government policies, consumer preferences, the pace of co-venturer/government funding, changes in the amount and timing of capital investments, 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. In Canada, proved undeveloped reserves are related to drilling activities in the offshore Hebron field and onshore Cold Lake operations. In Australia, proved undeveloped reserves are associated with future compression for the Gorgon Jansz LNG project. In Kazakhstan, the proved undeveloped reserves are related to the remainder of the initial development of the producing 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.

### 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.

	2018		2017		2016	
	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
<b>Crude oil and natural gas liquids production</b>	<i>(thousands of barrels daily)</i>					
<b>Consolidated Subsidiaries</b>						
United States	395	101	361	96	347	87
Canada/Other Americas (1)	62	6	44	6	53	6
Europe	101	27	147	31	171	31
Africa	377	10	412	11	459	15
Asia	398	25	373	26	383	27
Australia/Oceania	31	16	35	19	37	19
Total Consolidated Subsidiaries	1,364	185	1,372	189	1,450	185
<b>Equity Companies</b>						
United States	54	1	55	2	58	2
Europe	4	-	4	-	2	-
Asia	226	62	235	64	232	65
Total Equity Companies	284	63	294	66	292	67
<b>Total crude oil and natural gas liquids production</b>	1,648	248	1,666	255	1,742	252
<b>Bitumen production</b>						
<b>Consolidated Subsidiaries</b>						
Canada/Other Americas	310		305		304	
<b>Synthetic oil production</b>						
<b>Consolidated Subsidiaries</b>						
Canada/Other Americas	60		57		67	
<b>Total liquids production</b>	2,266		2,283		2,365	
	<i>(millions of cubic feet daily)</i>					
<b>Natural gas production available for sale</b>						
<b>Consolidated Subsidiaries</b>						
United States	2,550		2,910		3,052	
Canada/Other Americas (1)	227		218		239	
Europe	925		1,046		1,093	
Africa	13		5		7	
Asia	838		906		927	
Australia/Oceania	1,325		1,310		887	

Edgar Filing: EXXON MOBIL CORP - Form 10-K

Total Consolidated Subsidiaries	5,878	6,395	6,205
<b>Equity Companies</b>			
United States	24	26	26
Europe	728	902	1,080
Asia	2,775	2,888	2,816
Total Equity Companies	3,527	3,816	3,922
<b>Total natural gas production available for sale</b>	<b>9,405</b>	<b>10,211</b>	<b>10,127</b>
	<i>(thousands of oil-equivalent barrels daily)</i>		
<b>Oil-equivalent production</b>	<b>3,833</b>	<b>3,985</b>	<b>4,053</b>

*(1) Other Americas includes crude oil production for 2018 of two thousand barrels daily and natural gas production available for sale for 2018, 2017 and 2016 of 28 million, 24 million, and 22 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.

	Canada/		Europe	Africa	Asia	Australia/		Total
	United States	Other Americas				Oceania		
<b>During 2018</b>	<i>(dollars per unit)</i>							
<b>Consolidated Subsidiaries</b>								
Average production prices								
Crude oil, per barrel	59.84	64.53	69.80	70.84	69.86	66.89	66.91	
NGL, per barrel	30.78	37.27	38.53	47.10	26.30	36.34	32.88	
Natural gas, per thousand cubic feet	2.14	1.68	6.97	1.96	2.33	6.39	3.87	
Bitumen, per barrel	-	28.66	-	-	-	-	28.66	
Synthetic oil, per barrel	-	54.85	-	-	-	-	54.85	
Average production costs, per oil-equivalent barrel - total	11.64	24.32	13.07	17.28	7.31	6.94	13.34	
Average production costs, per barrel - bitumen	-	22.93	-	-	-	-	22.93	
Average production costs, per barrel - synthetic oil	-	45.33	-	-	-	-	45.33	
<b>Equity Companies</b>								
Average production prices								
Crude oil, per barrel	66.30	-	63.92	-	67.31	-	67.07	
NGL, per barrel	27.16	-	-	-	45.10	-	44.64	
Natural gas, per thousand cubic feet	2.19	-	5.03	-	6.31	-	6.01	
Average production costs, per oil-equivalent barrel - total	24.71	-	16.30	-	1.49	-	4.96	
<b>Total</b>								
Average production prices								
Crude oil, per barrel	60.61	64.53	69.57	70.84	68.92	66.89	66.93	
NGL, per barrel	30.72	37.27	38.53	47.10	39.69	36.34	35.85	
Natural gas, per thousand cubic feet	2.14	1.68	6.11	1.96	5.38	6.39	4.67	
Bitumen, per barrel	-	28.66	-	-	-	-	28.66	
Synthetic oil, per barrel	-	54.85	-	-	-	-	54.85	
Average production costs, per oil-equivalent barrel - total	12.43	24.32	14.06	17.31	3.98	6.94	11.29	
Average production costs, per barrel - bitumen	-	22.93	-	-	-	-	22.93	
Average production costs, per barrel - synthetic oil	-	45.33	-	-	-	-	45.33	
<b>During 2017</b>								
<b>Consolidated Subsidiaries</b>								
Average production prices								
Crude oil, per barrel	46.71	52.42	52.02	54.70	53.26	53.61	51.88	
NGL, per barrel	24.20	27.07	30.96	37.38	22.69	33.15	26.88	
Natural gas, per thousand cubic feet	2.03	2.03	5.48	1.51	2.05	4.22	3.04	

Edgar Filing: EXXON MOBIL CORP - Form 10-K

Bitumen, per barrel	-	29.70	-	-	-	-	29.70
Synthetic oil, per barrel	-	52.72	-	-	-	-	52.72
Average production costs, per oil-equivalent barrel - total	10.85	23.44	12.25	13.33	8.07	6.30	12.33
Average production costs, per barrel - bitumen	-	21.39	-	-	-	-	21.39
Average production costs, per barrel - synthetic oil	-	44.21	-	-	-	-	44.21

**Equity Companies**

Average production prices							
Crude oil, per barrel	49.13	-	47.69	-	50.27	-	50.02
NGL, per barrel	21.78	-	-	-	38.23	-	37.81
Natural gas, per thousand cubic feet	2.42	-	4.81	-	4.15	-	4.30
Average production costs, per oil-equivalent barrel - total	23.38	-	7.45	-	1.18	-	3.51

**Total**

Average production prices							
Crude oil, per barrel	47.03	52.42	51.91	54.70	52.12	53.61	51.56
NGL, per barrel	24.16	27.07	30.96	37.38	33.79	33.15	29.70
Natural gas, per thousand cubic feet	2.03	2.03	5.17	1.51	3.65	4.22	3.51
Bitumen, per barrel	-	29.70	-	-	-	-	29.70
Synthetic oil, per barrel	-	52.72	-	-	-	-	52.72
Average production costs, per oil-equivalent barrel - total	11.61	23.44	10.79	13.33	4.02	6.30	10.12
Average production costs, per barrel - bitumen	-	21.39	-	-	-	-	21.39
Average production costs, per barrel - synthetic oil	-	44.21	-	-	-	-	44.21

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
<b>During 2016</b>							
<b>Consolidated Subsidiaries</b>							
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
<b>Equity Companies</b>							
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
<b>Total</b>							
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

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. Natural 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**

	<b>2018</b>	<b>2017</b>	<b>2016</b>
<b>Net Productive Exploratory Wells Drilled</b>			
<b>Consolidated Subsidiaries</b>			
United States	1	-	-
Canada/Other Americas	4	5	2
Europe	-	-	1
Africa	1	1	1
Asia	-	-	-
Australia/Oceania	1	-	-
Total Consolidated Subsidiaries	7	6	4
<b>Equity Companies</b>			
United States	-	-	-
Europe	-	-	1
Africa	-	-	-
Asia	-	-	-
Total Equity Companies	-	-	1
<b>Total productive exploratory wells drilled</b>	<b>7</b>	<b>6</b>	<b>5</b>
<b>Net Dry Exploratory Wells Drilled</b>			
<b>Consolidated Subsidiaries</b>			
United States	3	-	-
Canada/Other Americas	-	-	1
Europe	1	-	-
Africa	-	2	1
Asia	-	-	-
Australia/Oceania	2	-	-
Total Consolidated Subsidiaries	6	2	2
<b>Equity Companies</b>			
United States	-	-	-
Europe	-	-	-
Africa	-	-	-
Asia	-	1	-
Total Equity Companies	-	1	-
<b>Total dry exploratory wells drilled</b>	<b>6</b>	<b>3</b>	<b>2</b>

	2018	2017	2016
<b>Net Productive Development Wells Drilled</b>			
<b>Consolidated Subsidiaries</b>			
United States	389	300	335
Canada/Other Americas	32	12	13
Europe	3	6	9
Africa	1	6	7
Asia	14	15	13
Australia/Oceania	-	1	-
Total Consolidated Subsidiaries	439	340	377
<b>Equity Companies</b>			
United States	168	154	121
Europe	3	1	2
Africa	-	-	-
Asia	6	3	3
Total Equity Companies	177	158	126
<b>Total productive development wells drilled</b>	<b>616</b>	<b>498</b>	<b>503</b>
<b>Net Dry Development Wells Drilled</b>			
<b>Consolidated Subsidiaries</b>			
United States	4	4	2
Canada/Other Americas	1	-	-
Europe	-	1	2
Africa	1	-	-
Asia	-	-	-
Australia/Oceania	-	-	-
Total Consolidated Subsidiaries	6	5	4
<b>Equity Companies</b>			
United States	-	-	-
Europe	-	-	-
Africa	-	-	-
Asia	-	-	-
Total Equity Companies	-	-	-
<b>Total dry development wells drilled</b>	<b>6</b>	<b>5</b>	<b>4</b>
<b>Total number of net wells drilled</b>	<b>635</b>	<b>512</b>	<b>514</b>

## 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 2018, the company's share of net production of synthetic crude oil was about 60 thousand barrels per day and share of net acreage was about 63 thousand acres in the Athabasca oil sands deposit.

**Kearl 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 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 2018, average net production at Kearl was about 191 thousand barrels per day.

At year-end 2018, an additional 3.4 billion barrels of bitumen at Kearl qualified as proved reserves under the SEC definition requiring calculations based on the average of the first-day-of-the-month price during the last 12-month period.

## 5. Present Activities

### A. Wells Drilling

	Year-End 2018		Year-End 2017	
	Gross	Net	Gross	Net
<b>Wells Drilling</b>				
<b>Consolidated Subsidiaries</b>				
United States	997	491	820	334
Canada/Other Americas	41	32	30	22
Europe	13	3	12	2
Africa	5	1	10	2
Asia	50	14	58	15
Australia/Oceania	4	2	3	1
Total Consolidated Subsidiaries	1,110	543	933	376
<b>Equity Companies</b>				
United States	7	1	10	1
Europe	1	1	8	3

Edgar Filing: EXXON MOBIL CORP - Form 10-K

Asia		17	4	14	4
	Total Equity Companies	25	6	32	8
<b>Total gross and net wells drilling</b>		1,135	549	965	384
	14				

---

## **B. Review of Principal Ongoing Activities**

### ***UNITED STATES***

ExxonMobil's year-end 2018 acreage holdings totaled 12.1 million net acres, of which 0.8 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska.

During the year, 554.6 net exploration and development wells were completed in the inland lower 48 states. Development activities focused on liquids-rich opportunities in the onshore U.S., primarily in the Permian Basin of West Texas and New Mexico 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 2018 was 0.7 million acres. A total of 3.5 net exploration and development wells were completed during the year.

Participation in Alaska production and development continued with a total of 7.3 net development wells completed.

### ***CANADA / OTHER AMERICAS***

#### *Canada*

*Oil and Gas Operations:* ExxonMobil's year-end 2018 acreage holdings totaled 6.9 million net acres, of which 3.6 million net acres were offshore. A total of 20.3 net development wells were completed during the year.

*In Situ Bitumen Operations:* ExxonMobil's year-end 2018 in situ bitumen acreage holdings totaled 0.7 million net onshore acres. A total of 10 net development wells at Cold Lake were completed during the year.

#### *Argentina*

ExxonMobil's net acreage totaled 0.3 million onshore acres at year-end 2018, and there were 3.6 net exploration and development wells completed during the year.

#### *Guyana*

ExxonMobil's net acreage totaled 4.7 million offshore acres at year-end 2018, and there were 2.8 net exploration wells completed during the year. Development activities continued on the Liza Phase 1 project.

### ***EUROPE***

#### *Germany*

A total of 2.3 million net onshore acres were held by ExxonMobil at year-end 2018, with 0.1 net development well completed during the year.

#### *Netherlands*

ExxonMobil's net interest in licenses totaled approximately 1.4 million acres at year-end 2018, of which 1.1 million acres were onshore. A total of 2.9 net exploration and development wells were completed during the year. In 2018, the

Dutch Cabinet notified Parliament of its intention to further reduce previously legislated Groningen gas extraction in response to seismic events over the last several years. Affiliates of the Corporation and their partners have actively been in discussions with the government on the associated implementation measures which resulted in a signed Heads of Agreement and the execution of additional implementation agreements.

*Norway*

ExxonMobil's net interest in licenses at year-end 2018 totaled approximately 0.1 million acres, all offshore. A total of 2.7 net development wells were completed in 2018.

*United Kingdom*

ExxonMobil's net interest in licenses at year-end 2018 totaled approximately 0.6 million acres, all offshore. A total of 0.6 net development wells were completed during the year. Development activities continued on the Penguins Redevelopment project.

## **AFRICA**

### *Angola*

ExxonMobil's net acreage totaled 0.2 million offshore acres at year-end 2018, with 2.0 net exploration and development wells completed during the year. On Block 32, development activities continued on the Kaombo Split Hub project as the Norte floating production storage and offloading (FPSO) vessel started up in 2018 and construction progressed on the Sul FPSO.

### *Chad*

At year-end 2018, ExxonMobil's net acreage holdings totaled 46 thousand onshore acres.

### *Equatorial Guinea*

ExxonMobil's acreage totaled 0.5 million net offshore acres at year-end 2018, with 0.8 net development well completed during the year. In 2018, ExxonMobil acquired deepwater acreage in Block EG-11.

### *Mozambique*

ExxonMobil's net acreage totaled approximately 2.6 million offshore acres at year-end 2018. ExxonMobil acquired an interest in offshore blocks Angoche A5-B, Zambezi Z5-C, and Zambezi Z5-D in December 2018. Development activities continued on the Coral South Floating LNG project during 2018.

### *Nigeria*

ExxonMobil's net acreage totaled 0.8 million offshore acres at year-end 2018, with 0.2 net development well completed during the year. In 2018, ExxonMobil relinquished approximately 0.3 million net acres offshore.

## **ASIA**

### *Azerbaijan*

At year-end 2018, ExxonMobil's net acreage totaled 7 thousand offshore acres. A total of 1.0 net development wells were completed during the year. The production sharing agreement (PSA) for the development of the Azeri-Chirag-Gunashli field was amended in September 2017 to extend the term by 25 years to 2049.

### *Indonesia*

At year-end 2018, ExxonMobil had 0.1 million net acres onshore. The Kedung Keris project was funded in 2018.

### *Iraq*

At year-end 2018, ExxonMobil's onshore acreage was 0.1 million net acres. A total of 1.7 net development wells were completed at the West Qurna Phase I oil field during the year. Oil field rehabilitation activities continued during 2018 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 has continued exploration activities.



*Kazakhstan*

ExxonMobil's net acreage totaled 0.1 million acres onshore and 0.2 million acres offshore at year-end 2018. A total of 7.2 net development wells were completed during 2018. Development activities continued on the Tengiz Expansion project.

*Malaysia*

ExxonMobil's interests in production sharing contracts covered 2.4 million net acres offshore at year-end 2018. During the year, a total of 0.5 net development well was completed.

*Qatar*

Through our joint ventures with Qatar Petroleum, ExxonMobil's net acreage totaled 65 thousand acres offshore at year-end 2018. 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. Development activities continued on the Barzan project in 2018.

*Russia*

ExxonMobil's net acreage holdings in Sakhalin at year-end 2018 were 85 thousand acres, all offshore. A total of 3.0 net development wells were completed.

ExxonMobil withdrew from the joint ventures with Rosneft for the Kara, Laptev, Chukchi and Black Seas and western Siberia, effective April 30, 2018. ExxonMobil continues to remain in compliance with all laws applicable to its operations and investments in the Russian Federation.

*Thailand*

ExxonMobil's net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2018.

*United Arab Emirates*

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2018. A total of 6.7 net development wells were completed. During 2018, development activities continued on the Upper Zakum 750 project, and work progressed on the Upper Zakum 1MBD project.

**AUSTRALIA / OCEANIA**

*Australia*

ExxonMobil's net acreage totaled 1.9 million acres offshore and 31 thousand acres onshore at year-end 2018. A total of 2.0 net exploration wells were completed during the year in the Bass Strait. The West Barracouta project was funded in 2018.

The co-venturer-operated Gorgon Jansz liquefied natural gas development consists of a subsea infrastructure for offshore production and transportation of the gas, a 15.6 million tonnes per year liquefied natural gas facility and a 280 million cubic feet per day domestic gas plant located on Barrow Island, Western Australia. The Gorgon Stage Two project was funded in 2018.

*Papua New Guinea*

A total of 9.9 million net acres were held by ExxonMobil at year-end 2018, of which 5.4 million net acres were offshore. A total of 0.5 net exploration well was completed during the year. The Papua New Guinea (PNG) liquefied natural gas 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 liquefied natural gas facility near Port Moresby. During 2018, operations were temporarily interrupted following a magnitude 7.5 earthquake.

**WORLDWIDE EXPLORATION**

At year-end 2018, 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 28.4 million net acres were held at year-end 2018 and 1.4 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 57 million barrels of oil and 2,400 billion cubic feet of natural gas for the period from 2019 through 2021. 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 2018				Year-End 2017			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
<b>Gross and Net Productive Wells</b>								
<b>Consolidated Subsidiaries</b>								
United States	20,996	8,460	25,061	14,396	20,679	8,366	27,700	15,979
Canada/Other Americas	5,037	4,781	4,262	1,650	4,877	4,618	4,273	1,646
Europe	981	256	648	261	1,016	267	664	268
Africa	1,221	472	12	5	1,222	474	15	6
Asia	891	286	133	79	900	299	139	82
Australia/Oceania	577	123	81	33	588	129	73	30
Total Consolidated Subsidiaries	29,703	14,378	30,197	16,424	29,282	14,153	32,864	18,011
<b>Equity Companies</b>								
United States	13,126	5,398	4,503	577	13,796	5,247	4,227	491
Europe	57	20	602	187	59	21	617	195
Asia	164	41	126	30	144	36	125	30
Total Equity Companies	13,347	5,459	5,231	794	13,999	5,304	4,969	716
<b>Total gross and net productive wells</b>	<b>43,050</b>	<b>19,837</b>	<b>35,428</b>	<b>17,218</b>	<b>43,281</b>	<b>19,457</b>	<b>37,833</b>	<b>18,727</b>

There were 28,847 gross and 24,696 net operated wells at year end 2018 and 30,263 gross and 25,827 net operated wells at year-end 2017. The number of wells with multiple completions was 947 gross in 2018 and 1,366 gross in 2017.

**B. Gross and Net Developed Acreage**

	<b>Year-End 2018</b>		<b>Year-End 2017</b>	
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>
	<i>(thousands of acres)</i>			
<b>Gross and Net Developed Acreage</b>				
<b>Consolidated Subsidiaries</b>				
United States	13,900	8,399	14,836	9,026
Canada/Other Americas (1)	3,596	2,325	3,604	2,328
Europe	2,937	1,315	2,970	1,335
Africa	2,492	866	2,492	866
Asia	1,939	563	1,983	586
Australia/Oceania	3,262	1,068	3,262	1,068
Total Consolidated Subsidiaries	28,126	14,536	29,147	15,209
<b>Equity Companies</b>				
United States	929	208	930	208
Europe	4,110	1,287	4,170	1,317
Asia	628	155	628	155
Total Equity Companies	5,667	1,650	5,728	1,680
<b>Total gross and net developed acreage</b>	<b>33,793</b>	<b>16,186</b>	<b>34,875</b>	<b>16,889</b>

(1) Includes developed acreage in Other Americas of 375 gross and 244 net thousands of acres for 2018 and 375 gross and 244 net thousands of acres for 2017.

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**

	<b>Year-End 2018</b>		<b>Year-End 2017</b>	
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>
	<i>(thousands of acres)</i>			
<b>Gross and Net Undeveloped Acreage</b>				
<b>Consolidated Subsidiaries</b>				
United States	7,421	3,427	7,506	3,489
Canada/Other Americas (1)	34,932	15,340	29,495	13,410
Europe	9,168	4,191	7,576	3,622
Africa	44,556	24,000	37,699	26,705
Asia	7,195	2,964	5,802	2,680
Australia/Oceania	15,337	10,756	15,976	11,125
Total Consolidated Subsidiaries	118,609	60,678	104,054	61,031
<b>Equity Companies</b>				
United States	203	76	207	77
Europe	100	25	100	25

Edgar Filing: EXXON MOBIL CORP - Form 10-K

Africa	596	149	596	149
Asia	73	5	191,147	63,633
Total Equity Companies	972	255	192,050	63,884
<b>Total gross and net undeveloped acreage</b>	<b>119,581</b>	<b>60,933</b>	<b>296,104</b>	<b>124,915</b>

*(1) Includes undeveloped acreage in Other Americas of 23,872 gross and 9,595 net thousands of acres for 2018 and 18,625 gross and 8,053 net thousands of acres for 2017.*

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 / OTHER AMERICAS***

#### *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. Offshore production licenses 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.

#### *Guyana*

The Petroleum (Exploration and Production) Act authorizes the government of Guyana to grant petroleum prospecting and production licenses and to enter into petroleum agreements for the exploration and production of hydrocarbons. Petroleum agreements provide for an exploration period of up to 10 years with a production period of 20 years with a 10 year extension.

### ***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 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 majority of traditional licenses currently issued have an initial exploration term of four years with a second term extension of four years, and a final production 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.

Terms for exploration acreage in technically challenged areas are governed by frontier production licenses, generally covering a larger initial area than traditional licenses, with an initial exploration term of six or nine years with a second term extension of six years, and a final production term of 18 years, with relinquishment of 75 percent of the original area after three years and 50 percent of the remaining acreage after the next three years. Innovate licenses issued replace traditional and frontier licenses and offer greater flexibility with respect to periods and work program commitments.

***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 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 30 years and in 2017 was extended by 20 years to 2050.

*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 ratified in 2018; 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.

*Mozambique*

Exploration and production activities are generally governed by concession contracts with the Government of the Republic of Mozambique, represented by the Ministry of Mineral Resources and Energy. An interest in Area 4 offshore Mozambique was acquired in 2017. Terms for Area 4 are governed by the Exploration and Production Concession Contract (EPCC) for Area 4 Offshore of the Rovuma Block. The EPCC expires 30 years after the approval of a plan of development for a given discovery area.

In 2018 an interest was acquired in offshore blocks, A5-B, Z5-C and Z5-D. Terms for the three blocks are governed by their respective EPCCs, which have an initial exploration phase that expires in 2022 with the possibility of two additional exploration phases expiring in 2024 and 2025. The EPCCs provide a development and production period that expires 30 years after the approval of a plan of development.

*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 10 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 10 years of their duration.

## **ASIA**

### *Azerbaijan*

The production sharing agreement (PSA) for the development of the Azeri-Chirag-Gunashli field was established for an initial period of 30 years starting from the PSA execution date in 1994. The PSA was amended in September 2017 to extend the term by 25 years to 2049.

Other exploration and production activities are governed by PSAs negotiated with the national oil company of Azerbaijan. The exploration period typically 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 Basra 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 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 exploration and production terms ranging up to 38 years. All extensions are subject to the national oil company's prior written approval. The production periods range from 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.

*Russia*

Terms for ExxonMobil's Sakhalin acreage are fixed by the current production sharing agreement (PSA) between the Russian government and the Sakhalin-1 consortium, of which ExxonMobil is the operator.

ExxonMobil withdrew from the joint ventures with Rosneft for the Kara, Laptev, Chukchi and Black Seas, effective April 30, 2018. ExxonMobil continues to remain in compliance with all laws applicable to its operations and investments in the Russian Federation.

*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. The term of the concession expires in 2021.

*United Arab Emirates*

An interest in the development and production activities of the Upper Zakum field, a major offshore field, was acquired in 2006. In 2017 the governing agreements were extended to 2051.

**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, trades 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 2018 (1)**

		<b>ExxonMobil Share KBD (2)</b>	<b>ExxonMobil Interest %</b>
<b>United States</b>			
Joliet	Illinois	236	100
Baton Rouge	Louisiana	503	100
Billings	Montana	60	100
Baytown	Texas	561	100
Beaumont	Texas	369	100
	Total United States	1,729	
<b>Canada</b>			
Strathcona	Alberta	191	69.6
Nanticoke	Ontario	113	69.6
Sarnia	Ontario	119	69.6
	Total Canada	423	
<b>Europe</b>			
Antwerp	Belgium	307	100
Fos-sur-Mer	France	133	82.9
Gravenchon	France	240	82.9
Karlsruhe	Germany	78	25
Treccate	Italy	132	74.8
Rotterdam	Netherlands	192	100
Slagen	Norway	116	100
Fawley	United Kingdom	262	100
	Total Europe	1,460	
<b>Asia Pacific</b>			
Altona	Australia	86	100
Fujian	China	67	25
Jurong/PAC	Singapore	592	100
Sriracha	Thailand	167	66
	Total Asia Pacific	912	
<b>Middle East</b>			
Yanbu	Saudi Arabia	200	50
<b>Total Worldwide</b>		4,724	

*(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 refining capacity for a minor interest held through equity securities 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 2018

#### United States

Owned/leased	-
Distributors/resellers	10,760
Total United States	10,760

#### Canada

Owned/leased	-
Distributors/resellers	2,035
Total Canada	2,035

#### Europe

Owned/leased	197
Distributors/resellers	5,636
Total Europe	5,833

#### Asia Pacific

Owned/leased	580
Distributors/resellers	1,013
Total Asia Pacific	1,593

#### Latin America

Owned/leased	-
Distributors/resellers	177
Total Latin America	177

#### Middle East/Africa

Owned/leased	225
Distributors/resellers	183
Total Middle East/Africa	408

#### Worldwide

Owned/leased	1,002
Distributors/resellers	19,804
Total Worldwide	20,806

**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 2018 (1)(2)**

			<b>Ethylene</b>	<b>Polyethylene</b>	<b>Polypropylene</b>	<b>Paraxylene</b>	<b>ExxonMobil Interest %</b>
<b>North America</b>							
Baton Rouge	Louisiana		1.1	1.3	0.4	-	100
Baytown	Texas		3.8	-	0.7	0.6	100
Beaumont	Texas		0.9	1.0	-	0.3	100
Mont Belvieu	Texas		-	2.3	-	-	100
Sarnia	Ontario		0.3	0.5	-	-	69.6
Total North America			6.1	5.1	1.1	0.9	
<b>Europe</b>							
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	
<b>Middle East</b>							
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	-	
<b>Asia Pacific</b>							
Fujian	China		0.3	0.2	0.2	0.2	25
Singapore	Singapore		1.9	1.9	0.9	1.8	100
Sriracha	Thailand		-	-	-	0.5	66
Total Asia Pacific			2.2	2.1	1.1	2.5	
<b>Total Worldwide</b>			10.7	9.9	2.7	4.1	

(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**

In a matter reported in the Corporation's Form 10-Q for the second quarter of 2018, the State of Ohio Department of Natural Resources, Division of Oil & Gas Resources Management (ODNR) and XTO Energy Inc. (XTO) signed a Compliance Agreement on December 21, 2018, regarding alleged violations by XTO of the Ohio Revised Code, Ohio Administrative Code, and implementing regulations arising out of the Schnegg well incident in Belmont County, Ohio, in early 2018. The Compliance Agreement settles the following alleged actions of XTO: (1) causing brine to be discharged and contact the ground and/or surface water; (2) failure to place cement in the casing string per Ohio codes; (3) allowing a well to flow gas uncontrolled; (4) failure to construct, drill and operate a well in the manner as permitted and planned; and (5) failure to notify the ODNR upon discovery a well had sustained annular pressure above the prescribed pressure. The penalty assessment was \$850,000, half paid to the ODNR on January 15, 2019, and half to be paid to 29 agencies located in Belmont County as designated by the ODNR.

In another matter relating to the Schnegg well incident, reported in the Corporation's Form 10-Q for the second quarter of 2018, the State of Ohio Environmental Protection Agency (OEPA) and XTO signed Final Findings and Orders on December 28, 2018, regarding OEPA allegations that XTO violated the Ohio Revised Code and implementing regulations, including but not limited to: (1) failure to maintain and operate its facility in a manner using good pollution control practices; (2) failure to provide a malfunction report; (3) failure to complete and properly report quarterly inspections; and (4) failure to submit site-specific work practice plans within applicable time limits. The penalty assessment of \$150,000 was paid on January 21, 2019, half to the OEPA and half to a Supplemental Environmental Project.

As reported in the Corporation's Form 10-Q for the first quarter of 2018, the Corporation received a proposed agreed order from the Texas Commission on Environmental Quality (TCEQ), dated March 15, 2018, related to routine Title V air operating permit investigations conducted by the TCEQ in 2017 of the Baytown Refinery in Texas. The proposed agreed order alleged that the refinery failed to authorize, monitor, or keep records on certain equipment and to comply with certain flare or fuel gas monitoring system availability requirements or concentration limits. After receipt of additional information from ExxonMobil and further evaluation of the alleged violations, the TCEQ has issued a revised proposed agreed order, reducing the number of alleged violations and agreeing to an administrative penalty of \$56,596 in settlement of these matters. The Agreed Order was signed by ExxonMobil on December 18, 2018, and ExxonMobil paid \$28,298 on January 10, 2019. The balance will be paid to a Supplemental Environmental Project upon endorsement by the TCEQ.

As last reported in the Corporation's Form 10-Q for the third quarter of 2018, on July 20, 2017, the United States Department of Treasury, Office of Foreign Assets Control (OFAC) assessed a civil penalty against Exxon Mobil Corporation, ExxonMobil Development Company and ExxonMobil Oil Corporation for violating the Ukraine-Related Sanctions Regulations, 31 C.F.R. part 589. The assessed civil penalty is in the amount of \$2,000,000. ExxonMobil and its affiliates have been and continue to be in compliance with all sanctions and disagree that any violation has occurred. ExxonMobil and its affiliates filed a complaint on July 20, 2017, in the United States Federal District Court, Northern District of Texas seeking judicial review of, and to enjoin, the civil penalty under the Administrative Procedures Act and the United States Constitution, including on the basis that it represents an arbitrary and capricious action by OFAC and a violation of the Company's due process rights.

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)]**

(positions and ages as of February 27, 2019)

<b>Darren W. Woods</b>	<i>Chairman of the Board</i>	
Held current title since:	January 1, 2017	Age: 54
Mr. Darren W. Woods 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 continues to hold as of this filing date.		
<b>Neil A. Chapman</b>	<i>Senior Vice President</i>	
Held current title since:	January 1, 2018	Age: 56
Mr. Neil A. Chapman was Senior Vice President, ExxonMobil Chemical Company April 1, 2011 – December 31, 2014. He was President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation January 1, 2015 – December 31, 2017. He became Senior Vice President of Exxon Mobil Corporation on January 1, 2018, a position he continues to hold as of this filing date.		
<b>Andrew P. Swiger</b>	<i>Senior Vice President</i>	
Held current title since:	April 1, 2009	Age: 62
Mr. Andrew P. Swiger became Senior Vice President of Exxon Mobil Corporation on April 1, 2009, a position he continues to hold as of this filing date.		
<b>Jack P. Williams, Jr.</b>	<i>Senior Vice President</i>	
Held current title since:	June 1, 2014	Age: 55
Mr. Jack P. Williams, Jr. 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 continues to hold as of this filing date.		
<b>Peter P. Clarke</b>	<i>Vice President</i>	
Held current title since:	March 1, 2018	Age: 53
Mr. Peter P. Clarke was Business Planning & Analysis Manager, ExxonMobil Gas & Power Marketing Company May 1, 2011 – April 30, 2014. He was Vice President, Asia Pacific, Africa & Power, ExxonMobil Gas & Power Marketing Company May 1, 2014 – February 28, 2015. He was Vice President, Asia Pacific, Africa, & Americas, ExxonMobil Gas & Power Marketing Company March 1, 2015 – June 30, 2015. He was Vice President, International Gas for ExxonMobil Gas & Power Marketing Company July 1, 2015 – February 28, 2018. He became President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation on March 1, 2018, positions he continues to hold as of this filing date.		

<b>Bradley W. Corson</b>	<i>Vice President</i>	
Held current title since:	March 1, 2015	Age: 57
<p>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 continues to hold as of this filing date.</p>		

Edgar Filing: EXXON MOBIL CORP - Form 10-K

<b>Neil W. Duffin</b>	<i>Vice President</i>	
Held current title since:	January 1, 2017	Age: 62
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 continues to hold as of this filing date.		
<b>Randall M. Ebner</b>	<i>Vice President and General Counsel</i>	
Held current title since:	November 1, 2016	Age: 63
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 continues to hold as of this filing date.		
<b>Stephen M. Greenlee</b>	<i>Vice President</i>	
Held current title since:	September 1, 2010	Age: 61
Mr. Stephen M. Greenlee became President of ExxonMobil Exploration Company and Vice President of Exxon Mobil Corporation on September 1, 2010, positions he continues to hold as of this filing date.		
<b>Neil A. Hansen</b>	<i>Vice President – Investor Relations and Secretary</i>	
Held current title since:	July 1, 2018	Age: 44
Mr. Neil A. Hansen was Affiliate Finance Manager, Treasurer's, Exxon Mobil Corporation May 1, 2013 – June 30, 2014. He was Thailand Lead Country Manager and Business Services Manager, Esso (Thailand) Public Company Ltd. July 1, 2014 – March 31, 2017. He was Controller, ExxonMobil Fuels, Lubricants & Specialties Marketing Company April 1, 2017 – December 31, 2017. He was Value Chain Controller, ExxonMobil Fuels & Lubricants Company January 1, 2018 – June 30, 2018. He became Vice President – Investor Relations and Secretary of Exxon Mobil Corporation on July 1, 2018, positions he continues to hold as of this filing date.		
<b>Liam M. Mallon</b>	<i>President, ExxonMobil Development Company</i>	
Held current title since:	January 1, 2017	Age: 56
Mr. Liam M. Mallon 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 continues to hold as of this filing date.		
<b>Bryan W. Milton</b>	<i>Vice President</i>	
Held current title since:	August 1, 2016	Age: 54
Mr. Bryan W. Milton was President of ExxonMobil Global Services Company April 1, 2011 – July 31, 2016. He was President of ExxonMobil Fuels, Lubricants & Specialties Marketing Company and Vice President of Exxon Mobil Corporation August 1, 2016 – December 31, 2017. He became President of ExxonMobil Fuels & Lubricants Company and Vice President of Exxon Mobil Corporation on January 1, 2018, positions he continues to hold as of this filing		



date.		
<b>Sara N. Ortwein</b>	<i>President, XTO Energy Inc., a subsidiary of the Corporation</i>	
Held current title since:	November 1, 2016	Age: 60
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 continues to hold as of this filing date.		
<b>David S. Rosenthal</b>	<i>Vice President and Controller</i>	
Held current title since:	October 1, 2008 (Vice President) September 1, 2014 (Controller)	Age: 62
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 continues to hold as of this filing date.		

<b>Robert N. Schleckser</b>	<i>Vice President and Treasurer</i>	
Held current title since:	May 1, 2011	Age: 62
Mr. Robert N. Schleckser became Vice President and Treasurer of Exxon Mobil Corporation on May 1, 2011, positions he continues to hold as of this filing date.		
<b>James M. Spellings, Jr.</b>	<i>Vice President and General Tax Counsel</i>	
Held current title since:	March 1, 2010	Age: 57
Mr. James M. Spellings, Jr. became Vice President and General Tax Counsel of Exxon Mobil Corporation on March 1, 2010, positions he continues to hold as of this filing date.		
<b>John R. Verity</b>	<i>Vice President</i>	
Held current title since:	January 1, 2018	Age: 60
Mr. John R. Verity was Vice President, Polyolefins, ExxonMobil Chemical Company October 17, 2008 – March 31, 2014. He was Vice President, Plastics & Resins, ExxonMobil Chemical Company April 1, 2014 – December 31, 2014. He was Senior Vice President, Polymers, ExxonMobil Chemical Company January 1, 2015 – December 31, 2017. He became President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation on January 1, 2018, positions he continues to hold as of this filing date.		
<b>Theodore J. Wojnar, Jr.</b>	<i>Vice President – Corporate Strategic Planning</i>	
Held current title since:	August 1, 2017	Age: 59
Mr. Theodore J. Wojnar, Jr. was President of ExxonMobil Research and Engineering Company April 1, 2011 – July 31, 2017. He became Vice President – Corporate Strategic Planning of Exxon Mobil Corporation on August 1, 2017, a position he continues to hold 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 and Item 12 in Part III of this report.

**Issuer Purchases of Equity Securities for Quarter Ended December 31, 2018**

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 2018	-		-	
November 2018	-		-	
December 2018	-		-	
Total	-		-	(See Note 1)

During the fourth quarter, the Corporation did not purchase any shares of its common stock for the treasury, and did not issue or sell any unregistered equity securities.

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,				
	2018	2017	2016	2015	2014
	<i>(millions of dollars, except per share amounts)</i>				
Sales and other operating revenue	279,332	237,162	200,628	239,854	367,647
Net income attributable to ExxonMobil	20,840	19,710	7,840	16,150	32,520
Earnings per common share	4.88	4.63	1.88	3.85	7.60
Earnings per common share - assuming dilution	4.88	4.63	1.88	3.85	7.60

Cash dividends per common share	3.23	3.06	2.98	2.88	2.70
Total assets	346,196	348,691	330,314	336,758	349,493
Long-term debt	20,538	24,406	28,932	19,925	11,653

**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 27, 2019, beginning with the section entitled “Report of Independent Registered Public Accounting Firm” and continuing through “Note 19: Income and Other Taxes”;
•	“Quarterly Information” (unaudited);
•	“Supplemental Information on Oil and Gas Exploration and Production Activities” (unaudited); and
•	“Frequently Used Terms” (unaudited).

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

**Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure**

None.

**Item 9A. Controls and Procedures****Management’s Evaluation of Disclosure Controls and Procedures**

As indicated in the certifications in Exhibit 31 of this report, the Corporation’s Chief Executive Officer, Principal Financial Officer and Principal Accounting Officer have evaluated the Corporation’s disclosure controls and procedures as of December 31, 2018. 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, 2018.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation’s internal control over financial reporting as of December 31, 2018, 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**

Reference is made to the section of this report titled “Executive Officers of the Registrant [pursuant to Instruction 3 to Regulation S-K, Item 401(b)]”.

Incorporated by reference to the following from the registrant’s definitive proxy statement for the 2019 annual meeting of shareholders (the “2019 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”, “Board Succession” and “Code of Ethics and Business Conduct” of the section entitled “Corporate Governance”; and
•	The “Audit Committee” portion, “Director Independence” portion and the membership table of the portions entitled “Board Meetings and Annual Meeting Attendance” and “Board Committees” 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”, “Executive Compensation Tables” and “Pay Ratio” of the registrant’s 2019 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 2019 Proxy Statement.

**Equity Compensation Plan Information**

<i>(a)</i>	<i>(b)</i>	<i>(c)</i>
Number of Securities to be Issued Upon Exercise of	Weighted-Average Exercise Price of Outstanding Options,	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding

<b>Plan Category</b>	<b>Outstanding Options, Warrants and Rights</b>	<b>Warrants and Rights</b>	<b>Securities Reflected in Column (a)]</b>
Equity compensation plans approved by security holders	39,847,820(1)	-	82,918,471(2)(3)
Equity compensation plans not approved by security holders	-	-	-
<b>Total</b>	<b>39,847,820</b>	<b>-</b>	<b>82,918,471</b>

(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 82,444,271 shares available for award under the 2003 Incentive Program and 474,200 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 2019 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 2019 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.

**Item 16. FORM 10-K SUMMARY**

None.

**FINANCIAL SECTION****TABLE OF CONTENTS**

Business Profile	36
Financial Information	37
Frequently Used Terms	38
Quarterly Information	40
Management's Discussion and Analysis of Financial Condition	
and Results of Operations	
Functional Earnings	41
Forward-Looking Statements	41
Overview	41
Business Environment and Risk Assessment	42
Review of 2018 and 2017 Results	46
Liquidity and Capital Resources	50
Capital and Exploration Expenditures	54
Taxes	55
Environmental Matters	56
Market Risks, Inflation and Other Uncertainties	56
Recently Issued Accounting Standards	58
Critical Accounting Estimates	58
Management's Report on Internal Control Over Financial Reporting	63
Report of Independent Registered Public Accounting Firm	64
Consolidated Financial Statements	
Statement of Income	66
Statement of Comprehensive Income	67
Balance Sheet	68
Statement of Cash Flows	69
Statement of Changes in Equity	70
Notes to Consolidated Financial Statements	
1. Summary of Accounting Policies	71
2. Accounting Changes	75
3. Miscellaneous Financial Information	76
4. Other Comprehensive Income Information	77
5. Cash Flow Information	78
6. Additional Working Capital Information	78
7. Equity Company Information	79
8. Investments, Advances and Long-Term Receivables	81
9. Property, Plant and Equipment and Asset Retirement Obligations	81
10. Accounting for Suspended Exploratory Well Costs	83
11. Leased Facilities	85
12. Earnings Per Share	86
13. Financial Instruments and Derivatives	86
14. Long-Term Debt	88
15. Incentive Program	89
16. Litigation and Other Contingencies	90

Edgar Filing: EXXON MOBIL CORP - Form 10-K

17. Pension and Other Postretirement Benefits	92
18. Disclosures about Segments and Related Information	100
19. Income and Other Taxes	103
Supplemental Information on Oil and Gas Exploration and Production Activities	107
Operating Information	122

**BUSINESS PROFILE**

<b>Financial</b>	<b>Earnings After Income Taxes</b>		<b>Average Capital Employed</b>		<b>Return on Average Capital Employed</b>		<b>Capital and Exploration Expenditures</b>	
	<b>2018</b>	<b>2017</b>	<b>2018</b>	<b>2017</b>	<b>2018</b>	<b>2017</b>	<b>2018</b>	<b>2017</b>
	<i>(millions of dollars)</i>				<i>(percent)</i>		<i>(millions of dollars)</i>	
Upstream								
United States	1,739	6,622	69,981	64,896	2.5	10.2	7,670	3,716
Non-U.S.	12,340	6,733	107,893	109,778	11.4	6.1	12,524	12,979
Total	14,079	13,355	177,874	174,674	7.9	7.6	20,194	16,695
Downstream								
United States	2,962	1,948	8,725	7,936	33.9	24.5	1,186	823
Non-U.S.	3,048	3,649	17,015	14,578	17.9	25.0	2,243	1,701
Total	6,010	5,597	25,740	22,514	23.3	24.9	3,429	2,524
Chemical								
United States	1,642	2,190	12,171	10,672	13.5	20.5	1,747	1,583
Non-U.S.	1,709	2,328	18,249	16,844	9.4	13.8	488	2,188
Total	3,351	4,518	30,420	27,516	11.0	16.4	2,235	3,771
Corporate and financing	(2,600)	(3,760)	(1,660)	(2,073)	-	-	65	90
Total	20,840	19,710	232,374	222,631	9.2	9.0	25,923	23,080

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

<b>Operating</b>	<b>2018</b>	<b>2017</b>	<b>2018</b>	<b>2017</b>
	<i>(thousands of barrels daily)</i>		<i>(thousands of barrels daily)</i>	
Net liquids production			Refinery throughput	
United States	551	514	United States	1,588
Non-U.S.	1,715	1,769	Non-U.S.	2,684
Total	2,266	2,283	Total	4,272
	<i>(millions of cubic feet daily)</i>		<i>(thousands of barrels daily)</i>	
Natural gas production available for sale			Petroleum product sales (2)	
United States	2,574	2,936	United States	2,210
Non-U.S.	6,831	7,275	Non-U.S.	3,302
Total	9,405	10,211	Total	5,512
	<i>(thousands of oil-equivalent barrels daily)</i>		<i>(thousands of metric tons)</i>	
Oil-equivalent production (1)	3,833	3,985	Chemical prime product sales (2) (3)	
			United States	9,824
				9,307

Non-U.S.	17,045	16,113
Total	26,869	25,420

- (1) *Natural gas is converted to an oil-equivalent basis at six million cubic feet per one 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 including ExxonMobil's share of equity company volumes and finished-product transfers to the Downstream.*

## FINANCIAL INFORMATION

	<b>2018</b>	<b>2017</b>	<b>2016</b>	<b>2015</b>	<b>2014</b>
	<i>(millions of dollars, except where stated otherwise)</i>				
Sales and other operating revenue	279,332	237,162	200,628	239,854	367,647
Earnings					
Upstream	14,079	13,355	196	7,101	27,548
Downstream	6,010	5,597	4,201	6,557	3,045
Chemical	3,351	4,518	4,615	4,418	4,315
Corporate and financing	(2,600)	(3,760)	(1,172)	(1,926)	(2,388)
Net income attributable to ExxonMobil	20,840	19,710	7,840	16,150	32,520
Earnings per common share (dollars)	4.88	4.63	1.88	3.85	7.60
Earnings per common share – assuming dilution (dollars)	4.88	4.63	1.88	3.85	7.60
Earnings to average ExxonMobil share of equity (percent)	11.0	11.1	4.6	9.4	18.7
Working capital	(9,165)	(10,637)	(6,222)	(11,353)	(11,723)
Ratio of current assets to current liabilities (times)	0.84	0.82	0.87	0.79	0.82
Additions to property, plant and equipment	20,051	24,901	16,100	27,475	34,256
Property, plant and equipment, less allowances	247,101	252,630	244,224	251,605	252,668
Total assets	346,196	348,691	330,314	336,758	349,493
Exploration expenses, including dry holes	1,466	1,790	1,467	1,523	1,669
Research and development costs	1,116	1,063	1,058	1,008	971
Long-term debt	20,538	24,406	28,932	19,925	11,653
Total debt	37,796	42,336	42,762	38,687	29,121
Debt to capital (percent)	16.0	17.9	19.7	18.0	13.9
Net debt to capital (percent) (1)	14.9	16.8	18.4	16.5	11.9
ExxonMobil share of equity at year-end	191,794	187,688	167,325	170,811	174,399
ExxonMobil share of equity per common share (dollars)	45.27	44.28	40.34	41.10	41.51
Weighted average number of common shares outstanding (millions)	4,270	4,256	4,177	4,196	4,282
Number of regular employees at year-end (thousands) (2)	71.0	69.6	71.1	73.5	75.3

(1) Debt net of cash.

(2) 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 is not significant.



**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.

<b>Cash flow from operations and asset sales</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars)</i>		
Net cash provided by operating activities	36,014	30,066	22,082
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	4,123	3,103	4,275
Cash flow from operations and asset sales	40,137	33,169	26,357

**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.

<b>Capital employed</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars)</i>		
Business uses: asset and liability perspective			
Total assets	346,196	348,691	330,314
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(39,880)	(39,841)	(33,808)



Edgar Filing: EXXON MOBIL CORP - Form 10-K

Total long-term liabilities excluding long-term debt	(69,992)	(72,014)	(79,914)
Noncontrolling interests share of assets and liabilities	(7,958)	(8,298)	(8,031)
Add ExxonMobil share of debt-financed equity company net assets	3,914	3,929	4,233
Total capital employed	232,280	232,467	212,794
Total corporate sources: debt and equity perspective			
Notes and loans payable	17,258	17,930	13,830
Long-term debt	20,538	24,406	28,932
ExxonMobil share of equity	191,794	187,688	167,325
Less noncontrolling interests share of total debt	(1,224)	(1,486)	(1,526)
Add ExxonMobil share of equity company debt	3,914	3,929	4,233
Total capital employed	232,280	232,467	212,794

38

---

**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.

<b>Return on average capital employed</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars)</i>		
Net income attributable to ExxonMobil	20,840	19,710	7,840
Financing costs (after tax)			
Gross third-party debt	(912)	(709)	(683)
ExxonMobil share of equity companies	(192)	(204)	(225)
All other financing costs – net	498	515	423
Total financing costs	(606)	(398)	(485)
Earnings excluding financing costs	21,446	20,108	8,325
Average capital employed	232,374	222,631	212,226
Return on average capital employed – corporate total	9.2%	9.0%	3.9%

## QUARTERLY INFORMATION

	2018					2017				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
<b>Volumes</b>										
Production of crude oil, natural gas liquids, synthetic oil and bitumen	<i>(thousands of barrels daily)</i>									
	2,216	2,212	2,286	2,348	2,266	2,333	2,269	2,280	2,251	2,283
Refinery throughput	4,293	4,105	4,392	4,298	4,272	4,324	4,345	4,287	4,207	4,291
Petroleum product sales (1)	5,432	5,502	5,616	5,495	5,512	5,395	5,558	5,542	5,624	5,530
Natural gas production available for sale	<i>(millions of cubic feet daily)</i>									
	10,038	8,613	9,001	9,974	9,405	10,908	9,920	9,585	10,441	10,211
Oil-equivalent production (2)	<i>(thousands of oil-equivalent barrels daily)</i>									
	3,889	3,647	3,786	4,010	3,833	4,151	3,922	3,878	3,991	3,985
Chemical prime product sales (1)	<i>(thousands of metric tons)</i>									
	6,668	6,852	6,677	6,672	26,869	6,072	6,120	6,446	6,782	25,420
<b>Summarized financial data</b>										
Sales and other operating revenue	<i>(millions of dollars)</i>									
	65,436	71,456	74,187	68,253	279,332	56,474	56,026	59,350	65,312	237,162
Gross profit (3)	16,187	16,622	18,656	16,268	67,733	14,030	13,120	15,086	14,126	56,362
Net income attributable to ExxonMobil(4)	4,650	3,950	6,240	6,000	20,840	4,010	3,350	3,970	8,380	19,710
<b>Per share data</b>										
Earnings per common share (5)	<i>(dollars per share)</i>									
	1.09	0.92	1.46	1.41	4.88	0.95	0.78	0.93	1.97	4.63
Earnings per common share – assuming dilution (5)	1.09	0.92	1.46	1.41	4.88	0.95	0.78	0.93	1.97	4.63

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

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

(3) Gross profit equals sales and other operating revenue less estimated costs associated with products sold. Effective January 1, 2018, the Corporation adopted the Accounting Standard Update, Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost which requires separate presentation of the non-service cost components of net benefit costs and increased previously reported gross profit by \$279 million for first quarter 2017, \$347 million for second quarter 2017, \$382 million for third quarter 2017, and \$430 million for fourth quarter 2017. See Note 2 to the financial

*statements, Accounting Changes.*

*(4) Fourth quarter 2018 included an impairment charge of \$429 million. Fourth quarter 2017 included a U.S. tax reform impact of \$5,942 million and an impairment charge of \$1,294 million.*

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

The 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 371,146 registered shareholders of ExxonMobil common stock at December 31, 2018. At January 31, 2019, the registered shareholders of ExxonMobil common stock numbered 370,064.

On January 30, 2019, the Corporation declared a \$0.82 dividend per common share, payable March 11, 2019.

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

### FUNCTIONAL EARNINGS

	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars, except per share amounts)</i>		
<b>Earnings (U.S. GAAP)</b>			
Upstream			
United States	1,739	6,622	(4,151)
Non-U.S.	12,340	6,733	4,347
Downstream			
United States	2,962	1,948	1,094
Non-U.S.	3,048	3,649	3,107
Chemical			
United States	1,642	2,190	1,876
Non-U.S.	1,709	2,328	2,739
Corporate and financing	(2,600)	(3,760)	(1,172)
Net income attributable to ExxonMobil (U.S. GAAP)	20,840	19,710	7,840
Earnings per common share	4.88	4.63	1.88
Earnings per common share – assuming dilution	4.88	4.63	1.88

*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, supply and mix; government policies relating to climate change, foreign relations and taxation; 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; technological developments; 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.

### 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 integrated business model involving exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty products.

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 depend on supply and demand and may be volatile on a short-term basis, ExxonMobil's investment decisions are grounded on fundamentals reflected in our long-term business outlook, and use 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 potential market conditions. Once major investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

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

### BUSINESS ENVIRONMENT AND RISK ASSESSMENT

#### Long-Term Business Outlook

The Long-Term Business Outlook is based on the Corporation's 2018 *Outlook for Energy*, which is used to help inform our long term business strategies and investment plans. By 2040, the world's population is projected at around 9.2 billion people, or about 1.7 billion more than in 2016. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 3 percent per year, with economic output nearly doubling by 2040. As economies and populations grow, and as living standards improve for billions of people, the need for energy is expected to continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 25 percent from 2016 to 2040. This increase in energy demand is expected to be driven by developing countries (i.e., those that are not member nations of the Organisation for Economic Co-operation and Development (OECD)).

As expanding prosperity helps drive 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 power generation, transportation, industrial applications, and residential and commercial needs.

Global electricity demand is expected to increase approximately 60 percent from 2016 to 2040, with developing countries likely to account for about 85 percent of the increase. Consistent with this projection, power generation is expected to remain the largest and fastest growing major segment of global primary energy demand, supported by a wide variety of energy sources. The share of coal fired generation is likely to decline substantially and approach 25 percent of the world's electricity in 2040, versus nearly 40 percent in 2016, 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 2016 to 2040, the amount of electricity supplied using natural gas, nuclear power, and renewables is likely to nearly double, and account for about 95 percent of the growth in electricity supplies. Electricity from wind and solar is likely to increase about 400 percent, helping total renewables (including other sources, e.g. hydropower) to account for about half of the increase in electricity supplies worldwide through 2040. Total renewables will likely reach nearly 35 percent of global electricity supplies by 2040. Natural gas and nuclear are also expected to increase shares over the period to 2040, reaching about 25 percent and 12 percent of global electricity supplies respectively by 2040. Supplies of electricity by energy type will reflect significant differences across regions reflecting a wide range of factors including the cost and availability of various energy supplies.

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase approximately 30 percent from 2016 to 2040. Transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Liquid fuels demand for light-duty vehicles is expected to remain relatively flat to 2040 as the impact of better fuel economy and significant growth in electric cars, led by China, Europe, and the United States, work to offset growth in the worldwide car fleet of about 75 percent. By 2040, light-duty vehicles are expected to account for about 20 percent of global liquid fuels demand. During the same time period, nearly all the world's transportation fleets are likely to continue to run on liquid fuels, which are widely available and offer practical advantages in providing a large quantity of energy in small volumes.

Liquid fuels provide the largest share of global energy supplies today reflecting broad-based availability, affordability, ease of transportation, 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 118 million barrels of oil equivalent per day, an increase of about 20

percent from 2016. The non-OECD share of global liquid fuels demand is expected to increase to about 65 percent by 2040, as liquid fuels demand in the OECD is likely to decline by close to 10 percent. Much of the global liquid fuels demand today is met by crude production from traditional conventional sources; these supplies will remain important and 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 to help 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, timely investments will remain critical to meeting global needs with reliable and affordable supplies.

Natural gas is a versatile and practical fuel for a wide variety of applications, and it is expected to grow the most of any primary energy type from 2016 to 2040, meeting more than 35 percent of global energy demand growth. Global natural gas demand is expected to rise nearly 40 percent from 2016 to 2040, with about 45 percent of that increase in the Asia Pacific region. Significant growth in supplies of unconventional gas – the natural gas found in shale and other tight rock formations – will help meet these needs. In total, about 55 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 global supply, meeting about two-thirds of worldwide demand in 2040. Liquefied natural gas (LNG) trade will expand significantly, meeting about one-third of the increase in global demand growth, with much of this supply expected to help meet rising demand in Asia Pacific.



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

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 2020-2025 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 exceed 15 percent of global 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 nearly 250 percent from 2016 to 2040, when they will likely be about 5 percent of the world energy mix.

The Corporation anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from increases in previously discovered fields. Technology will underpin these increases. The investments to develop and supply resources to meet global demand through 2040 will be significant – even if demand remains flat. This reflects a fundamental aspect of the oil and natural gas business, in that, as the International Energy Agency (IEA) notes in its *World Energy Outlook 2018*, a “key underlying driver for new investment is declining output from existing fields.” According to the IEA's New Policies Scenario, the investment required to meet oil and natural gas supply requirements worldwide over the period 2018-2040 will be about \$21 trillion (measured in 2017 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*. The climate accord reached at the Conference of the Parties (COP 21) in Paris set many new goals, and many related policies are still emerging. Our *Outlook* reflects an environment with 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 (UNFCCC) 2015 Paris Agreement. Our *Outlook* seeks to identify potential impacts of climate related policies, which often target specific sectors. It estimates potential impacts of these policies on consumer energy demand by using various assumptions and tools – including, depending on the sector, application of a proxy cost of carbon or assessment of targeted policies (e.g. automotive fuel economy standards). For purposes of the *Outlook*, a proxy cost on energy-related CO<sub>2</sub> 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.

Practical solutions to the world's energy and climate challenges will benefit from market competition as well as well informed, well designed, and transparent policy approaches that carefully weigh costs and benefits. Such policies are likely to help manage the risks of climate change while also enabling societies to pursue other high priority goals around the world – including clean air and water, access to reliable, affordable energy, and economic progress for all people. 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 sustain a diverse growth 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 strategies guide our global Upstream business, including 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. Based on current investment plans, oil-equivalent production from the Americas is expected to increase to be a majority of total production over the next several years. Further, the proportion of our global production from unconventional, deepwater, and LNG resource types, currently contributes over a third of global production, and is expected to grow to be more than half in the next few years.

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

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 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 general economic activities, levels of prosperity, technology advances, consumer preference and government policies. 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.

In 2018, the Upstream business produced 3.8 million oil-equivalent barrels per day. During the year, the Corporation added 4.5 billion oil-equivalent barrels of proved reserves. The Corporation continued to have exploration success in Guyana and also made strategic acreage acquisitions in Mozambique, Brazil, Papua New Guinea and U.S. tight oil.

### Downstream

ExxonMobil's Downstream is a large, diversified business with global logistics, trading, refining, and marketing. The Corporation has a presence with established markets in the Americas 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 21 refineries, located in 14 countries, with distillation capacity of 4.7 million barrels per day and lubricant basestock manufacturing capacity of 128 thousand barrels per day. ExxonMobil's fuels and lubes value chains have significant global reach, with multiple channels to market serving a diverse customer base. Our portfolio of world-renowned brands includes *Exxon*, *Mobil*, *Esso*, *Synergy*, and *Mobil 1*.

Demand for products continued to grow in 2018. North America's margins strengthened and refineries within the region also benefitted from crude differentials associated with the Permian Basin and Western Canada. Margins in Europe and Asia weakened under pressure from lower cost production from North America and increased product exports from China. In the near term, we see variability in refining margins as new capacity additions are expected to outpace capacity rationalization and growth in global demand, 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 volatile subject to the pace of new capacity growth relative to global demand growth. ExxonMobil's integration including logistics, trading, refining, and marketing enhances our ability to generate returns across the value chain 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.

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

ExxonMobil continued to progress the multi-year transition of the direct served (i.e., dealer, company operated) retail network in portions of Europe to a more capital efficient Branded Wholesaler model. The lubricants business continues to grow, leveraging world class brands and integration with industry leading basestock refining capability. Through the Mobil Branded properties, such as *Mobil 1*, Mobil is the worldwide leader among synthetic motors oils.

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. At the end of 2018, three key projects are in operation with the new delayed coker unit at the refinery in Antwerp, Belgium, to upgrade low value bunker fuel into higher value diesel products, and the proprietary hydrocracker at the refinery in Rotterdam, Netherlands, to produce higher value ultra-low sulfur diesel and Group II basestocks. Finally, the new hydrofiner at the Beaumont, Texas, refinery was completed, which increases production of ultra-low sulfur fuels by approximately 40,000 barrels per day.

### Chemical

ExxonMobil is a major manufacturer and marketer of petrochemicals and a wide variety of specialty products. ExxonMobil sustains its competitive advantage through continued operational excellence, investment and cost discipline, a balanced portfolio of products, and integration with downstream and upstream operations, all underpinned by proprietary technology.

Demand for products continued to grow in 2018. Polyolefin and specialty product margins weakened with capacity additions outpacing global demand growth.

Over the long term, demand for chemical products is forecast to outpace growth in global GDP and energy demand for the next two decades. ExxonMobil estimates that global demand for chemicals will rise by approximately 45 percent over the next decade. ExxonMobil's integration with refining enhances our ability to generate returns across the value chain in chemical businesses.

In 2018, we completed start-up of the new world-scale ethane cracker in Baytown, Texas, the specialty elastomer plant expansion in Newport, Wales, and the new halobutyl rubber unit in Singapore to further extend our specialty product capacity. Construction continues on the expansion of the polyethylene plant in Beaumont, Texas, with startup anticipated in 2019, to capitalize on advantaged feedstock and energy supplies in North America and to meet rapidly growing demand for performance polymers. Work continues to integrate the Singapore Banyan Aromatics unit, acquired in 2017, with our other Singapore facilities to meet growing demand for chemicals products in Asia Pacific. In addition, ExxonMobil announced plans for a flexible-feed cracker in Guangdong Province, China, and a joint venture ethane cracker and associated products with SABIC to be located in San Patricio County, Texas.

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

### REVIEW OF 2018 AND 2017 RESULTS

	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars)</i>		
<b>Earnings (U.S. GAAP)</b>			
Net income attributable to ExxonMobil (U.S. GAAP)	20,840	19,710	7,840

### Upstream

	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars)</i>		
Upstream			
United States	1,739	6,622	(4,151)
Non-U.S.	12,340	6,733	4,347
Total	14,079	13,355	196

### 2018

Upstream earnings were \$14,079 million, up \$724 million from 2017.

- Higher realizations increased earnings by \$7 billion.
- Unfavorable volume and mix effects decreased earnings by \$240 million.
- All other items decreased earnings by \$6.1 billion, primarily due to lower favorable impacts of \$6.9 billion from U.S. tax reform, partly offset by lower asset impairments of \$1.1 billion.
- U.S. Upstream earnings were \$1,739 million, including asset impairments of \$297 million.
- Non U.S. Upstream earnings were \$12,340 million, including a favorable impact of \$271 million from U.S. tax reform.
- On an oil equivalent basis, production of 3.8 million barrels per day was down 4 percent compared to 2017.
- Liquids production of 2.3 million barrels per day decreased 17,000 barrels per day as growth in North America was more than offset by decline, lower entitlements, and divestments.
- Natural gas production of 9.4 billion cubic feet per day decreased 806 million cubic feet per day from 2017 due to decline, lower entitlements, divestments, and higher downtime.

### 2017

Upstream earnings were \$13,355 million, up \$13,159 million from 2016.

- Higher realizations increased earnings by \$5.3 billion.
- Unfavorable volume and mix effects decreased earnings by \$440 million.
- All other items increased earnings by \$8.3 billion, primarily due to the \$7.1 billion non cash impact from U.S. tax reform, lower asset impairments of \$659 million, lower expenses, and gains from asset management activity.
- U.S. Upstream earnings were \$6,622 million in 2017, including \$7.6 billion of U.S. tax reform benefits and asset impairments of \$521 million.
- Non U.S. Upstream earnings were \$6,733 million, including asset impairments of \$983 million and unfavorable impacts of \$480 million from U.S. tax reform.
- On an oil equivalent basis, production of 4 million barrels per day was down 2 percent compared to 2016.
- Liquids production of 2.3 million barrels per day decreased 82,000 barrels per day as field decline and lower entitlements were partly offset by increased project volumes and work programs.
- Natural gas production of 10.2 billion cubic feet per day increased 84 million cubic feet per day from 2016 as project ramp up, primarily in Australia, was partly offset by field decline and regulatory restrictions in the Netherlands.

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

### Upstream Additional Information

	2018	2017
	<i>(thousands of barrels daily)</i>	
<b>Volumes Reconciliation</b> (Oil-equivalent production) <i>(1)</i>		
Prior Year	3,985	4,053
Entitlements - Net Interest	(3)	-
Entitlements - Price / Spend / Other	(68)	(62)
Quotas	-	-
Divestments	(58)	(15)
Growth / Other	(23)	9
Current Year	3,833	3,985

*(1) Natural gas is converted to an oil-equivalent basis at six million cubic feet per one 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.

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

	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars)</i>		
Downstream			
United States	2,962	1,948	1,094
Non-U.S.	3,048	3,649	3,107
Total	6,010	5,597	4,201

**2018**

Downstream earnings of \$6,010 million increased \$413 million from 2017.

- Margins increased earnings by \$660 million primarily due to the capture of North American crude differentials.
- Volume and mix effects increased earnings by \$650 million due to improved yield/sales mix.
- All other items decreased earnings by \$900 million, mainly driven by the absence of favorable U.S. tax reform impacts of \$618 million, unfavorable foreign exchange impacts, and higher downtime/maintenance, partly offset by higher divestment gains and favorable tax impacts.
- U.S. Downstream earnings were \$2,962 million, compared to \$1,948 million in the prior year which included a favorable impact of \$618 million from U.S. tax reform.
- Non U.S. Downstream earnings were \$3,048 million, compared to \$3,649 million in the prior year.
- Petroleum product sales of 5.5 million barrels per day were 18,000 barrels per day lower than 2017.

**2017**

Downstream earnings of \$5,597 million increased \$1,396 million from 2016.

- Stronger refining and marketing margins increased earnings by \$1.5 billion.
- Volume and mix effects decreased earnings by \$30 million.
- All other items decreased earnings by \$40 million, driven by the absence of a \$904 million gain from the Canadian retail assets sale, and Hurricane Harvey related expenses, which were mostly offset by \$618 million of U.S. tax reform impacts and non U.S. asset management gains in 2017.
- U.S. Downstream earnings were \$1,948 million, including favorable U.S. tax reform impacts of \$618 million.
- Non U.S. Downstream earnings were \$3,649 million, compared to \$3,107 million in the prior year.

- Petroleum product sales of 5.5 million barrels per day were 48,000 barrels per day higher than 2016.

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

### Chemical

	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars)</i>		
Chemical			
United States	1,642	2,190	1,876
Non-U.S.	1,709	2,328	2,739
Total	3,351	4,518	4,615

### 2018

Chemical earnings of \$3,351 million decreased \$1,167 million from 2017.

- Weaker margins decreased earnings by \$910 million.
- Volume and mix effects increased earnings by \$280 million, primarily due to sales growth.
- All other items decreased earnings by \$540 million, primarily due to the absence of favorable impacts from U.S. tax reform of \$335 million, higher downtime/maintenance, and growth-related expenses, partly offset by a favorable tax item and favorable foreign exchange impacts.
- U.S. Chemical earnings were \$1,642 million in 2018, compared with \$2,190 million in the prior year which included \$335 million in favorable impacts from U.S. tax reform.
- Non U.S. Chemical earnings were \$1,709 million, compared with \$2,328 million in the prior year.
- Prime product sales of 26.9 million metric tons were up 1.4 million metric tons from 2017.

### 2017

Chemical earnings of \$4,518 million decreased \$97 million from 2016.

- Weaker margins decreased earnings by \$260 million.
- Volume and mix effects increased earnings by \$100 million.
- All other items increased earnings by \$60 million, primarily due to U.S. tax reform of \$335 million and improved inventory effects, partially offset by higher expenses from increased turnaround activity and new business growth.
- U.S. Chemical earnings were \$2,190 million in 2017, including favorable U.S. tax reform impacts of \$335 million.
- Non U.S. Chemical earnings of \$2,328 million were \$411 million lower than prior year.

- Prime product sales of 25.4 million metric tons were up 495,000 metric tons from 2016.

**Corporate and Financing**

	<b>2018</b>	<b>2017</b>	<b>2016</b>
		<i>(millions of dollars)</i>	
Corporate and financing	(2,600)	(3,760)	(1,172)

**2018**

Corporate and financing expenses were \$2,600 million in 2018 compared to \$3,760 million in 2017, with the decrease mainly due to absence of prior year unfavorable impacts of \$2.1 billion from U.S. tax reform, partly offset by higher pension and financing related costs, lower U.S. tax rate, and lower net favorable tax items.

**2017**

Corporate and financing expenses were \$3,760 million in 2017 compared to \$1,172 million in 2016, with the increase mainly due to unfavorable impacts of \$2.1 billion from U.S. tax reform and the absence of favorable non-U.S. tax items.

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

### LIQUIDITY AND CAPITAL RESOURCES

#### Sources and Uses of Cash

	2018	2017	2016
	<i>(millions of dollars)</i>		
Net cash provided by/(used in)			
Operating activities	36,014	30,066	22,082
Investing activities	(16,446)	(15,730)	(12,403)
Financing activities	(19,446)	(15,130)	(9,293)
Effect of exchange rate changes	(257)	314	(434)
Increase/(decrease) in cash and cash equivalents	(135)	(480)	(48)
		<b>(December 31)</b>	
Total cash and cash equivalents	3,042	3,177	3,657

Total cash and cash equivalents were \$3.0 billion at the end of 2018, down \$0.1 billion from the prior year. The major sources of funds in 2018 were net income including noncontrolling interests of \$21.4 billion, the adjustment for the noncash provision of \$18.7 billion for depreciation and depletion, and proceeds from asset sales of \$4.1 billion. The major uses of funds included spending for additions to property, plant and equipment of \$19.6 billion, dividends to shareholders of \$13.8 billion, net debt repayments of \$4.9 billion, an increase in inventories of \$3.1 billion, the adjustment for net gains on asset sales of \$2.0 billion, and additional investments and advances of \$2.0 billion.

Total cash and cash equivalents were \$3.2 billion at the end of 2017, down \$0.5 billion from the prior year. The major sources of funds in 2017 were net income including noncontrolling interests of \$19.8 billion, the adjustment for the noncash provision of \$19.9 billion for depreciation and depletion, proceeds from asset sales of \$3.1 billion, and other investing activities including collection of advances of \$2.1 billion. The major uses of funds included spending for additions to property, plant and equipment of \$15.4 billion, dividends to shareholders of \$13.0 billion, the adjustment for noncash deferred income tax credits of \$8.6 billion, and additional investments and advances of \$5.5 billion.

The Corporation has access to significant capacity of long-term and short-term liquidity. Internally generated funds are generally expected to cover financial requirements, supplemented by short-term and long-term debt as required. On December 31, 2018, the Corporation had unused committed short-term lines of credit of \$5.3 billion and unused committed long-term lines of credit of \$0.2 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 or acquire 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 and growth in key tight-oil plays, 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 2018 were \$25.9 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment level of approximately \$30 billion in 2019.

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

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.

ExxonMobil closely monitors the potential impacts of Brexit and LIBOR reform under a number of scenarios and has taken steps to mitigate their potential impact. Accordingly, ExxonMobil does not believe these events represent a material risk to the Corporation's consolidated results of operations or financial condition.

### **Cash Flow from Operating Activities**

#### **2018**

Cash provided by operating activities totaled \$36.0 billion in 2018, \$5.9 billion higher than 2017. The major source of funds was net income including noncontrolling interests of \$21.4 billion, an increase of \$1.6 billion. The noncash provision for depreciation and depletion was \$18.7 billion, down \$1.1 billion from the prior year. The adjustment for the net gain on asset sales was \$2.0 billion, an increase of \$1.7 billion. The adjustment for dividends received less than equity in current earnings of equity companies was a reduction of \$1.7 billion, compared to an increase of \$0.1 billion in 2017. The adjustment for deferred income tax credits was \$0.1 billion, compared to \$8.6 billion in 2017. Changes in operational working capital, excluding cash and debt, decreased cash in 2018 by \$1.4 billion.

#### **2017**

Cash provided by operating activities totaled \$30.1 billion in 2017, \$8.0 billion higher than 2016. The major source of funds was net income including noncontrolling interests of \$19.8 billion, an increase of \$11.5 billion. The noncash provision for depreciation and depletion was \$19.9 billion, down \$2.4 billion from the prior year. The adjustment for deferred income tax credits was \$8.6 billion, compared to \$4.4 billion in 2016. Changes in operational working capital, excluding cash and debt, decreased cash in 2017 by \$0.6 billion.

### **Cash Flow from Investing Activities**

#### **2018**



Cash used in investing activities netted to \$16.4 billion in 2018, \$0.7 billion higher than 2017. Spending for property, plant and equipment of \$19.6 billion increased \$4.2 billion from 2017. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of \$4.1 billion compared to \$3.1 billion in 2017. Additional investments and advances were \$3.5 billion lower in 2018, while proceeds from other investing activities including collection of advances decreased by \$1.1 billion.

## **2017**

Cash used in investing activities netted to \$15.7 billion in 2017, \$3.3 billion higher than 2016. Spending for property, plant and equipment of \$15.4 billion decreased \$0.8 billion from 2016. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of \$3.1 billion compared to \$4.3 billion in 2016. Additional investments and advances were \$4.1 billion higher in 2017, while proceeds from other investing activities including collection of advances increased by \$1.2 billion.

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

### Cash Flow from Financing Activities

#### 2018

Cash used in financing activities was \$19.4 billion in 2018, \$4.3 billion higher than 2017. Dividend payments on common shares increased to \$3.23 per share from \$3.06 per share and totaled \$13.8 billion. Total debt decreased \$4.5 billion to \$37.8 billion at year end. The reduction was principally driven by net short-term debt and commercial paper repayments of \$5.0 billion.

ExxonMobil share of equity increased \$4.1 billion to \$191.8 billion. The addition to equity for earnings was \$20.8 billion. This was partly offset by reductions for distributions to ExxonMobil shareholders of \$13.8 billion, all in the form of dividends. Foreign exchange translation effects of \$4.4 billion for the stronger U.S. currency reduced equity, while a \$1.1 billion change in the funded status of the postretirement benefits reserves increased equity.

During 2018, Exxon Mobil Corporation acquired 8 million shares of its common stock for the treasury. Purchases were made to offset shares or units settled in shares issued in conjunction with the company's benefit plans and programs. Shares outstanding decreased from 4,239 million to 4,237 million at the end of 2018.

#### 2017

Cash used in financing activities was \$15.1 billion in 2017, \$5.8 billion higher than 2016. Dividend payments on common shares increased to \$3.06 per share from \$2.98 per share and totaled \$13.0 billion. Total debt decreased \$0.4 billion to \$42.3 billion at year end. The reduction was principally driven by net repayments of \$1.0 billion, and included short-term debt repayments of \$5.0 billion that were partly offset by additions in commercial paper and other debt of \$4.0 billion.

ExxonMobil share of equity increased \$20.4 billion to \$187.7 billion. The addition to equity for earnings was \$19.7 billion. This was partly offset by reductions for distributions to ExxonMobil shareholders of \$13.0 billion, all in the form of dividends. Foreign exchange translation effects of \$5.0 billion for the weaker U.S. currency and a \$1.0 billion change in the funded status of the postretirement benefits reserves both increased equity. Shares issued for acquisitions added \$7.8 billion to equity.

During 2017, Exxon Mobil Corporation acquired 10 million shares of its common stock for the treasury. Purchases were made to offset shares or units settled in shares issued in conjunction with the company's benefit plans and programs. Shares outstanding increased from 4,148 million to 4,239 million at the end of 2017, mainly due to a total of 96 million shares issued for the acquisitions of InterOil Corporation and of companies that hold acreage in the Permian Basin.

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

### Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2018. The table combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

Commitments	Note Reference Number	Payments Due by Period				Total
		2019	2020- 2021	2022- 2023	2024 and Beyond	
		<i>(millions of dollars)</i>				
Long-term debt (1)	14	-	4,210	3,145	13,183	20,538
– Due in one year (2)	6	4,070	-	-	-	4,070
Asset retirement obligations (3)	9	918	1,484	860	8,841	12,103
Pension and other postretirement obligations (4)	17	2,666	1,899	1,858	13,594	20,017
Operating leases (5)	11	1,156	1,750	1,003	2,203	6,112
Take-or-pay and unconditional purchase obligations (6)		3,628	6,618	5,566	14,903	30,715
Firm capital commitments (7)		7,044	2,246	1,137	1,187	11,614

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 \$9.2 billion as of December 31, 2018, 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 and Other Taxes".

Notes:

(1) Includes capitalized lease obligations of \$1,303 million.

(2) The amount due in one year is included in Notes and loans payable of \$17,258 million.

(3) Asset retirement obligations are 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 2019 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 and other assets. Total includes \$623 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 \$30,715 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 \$11.6 billion, including \$2.5 billion in the U.S.*

*Firm capital commitments for the non-U.S. Upstream of \$8.6 billion were primarily associated with projects in Guyana, Africa, United Kingdom, United Arab Emirates, Malaysia, Australia, Canada and Norway. The Corporation expects to fund the majority of these commitments with internally generated funds, supplemented by short-term and long-term debt as required.*

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

### Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2018, 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, 2018, the Corporation's unused short-term committed lines of credit totaled \$5.3 billion (Note 6) and unused long-term committed lines of credit totaled \$0.2 billion (Note 14). The table below shows the Corporation's consolidated debt-to-capital ratios. The data demonstrates the Corporation's creditworthiness.

	<b>2018</b>	<b>2017</b>	<b>2016</b>
Debt to capital (percent)	16.0	17.9	19.7
Net debt to capital (percent)	14.9	16.8	18.4

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

**2018**

**2017**

Edgar Filing: EXXON MOBIL CORP - Form 10-K

	<b>U.S.</b>	<b>Non-U.S.</b>	<b>Total</b>	<b>U.S.</b>	<b>Non-U.S.</b>	<b>Total</b>
	<i>(millions of dollars)</i>					
Upstream (1)	7,670	12,524	20,194	3,716	12,979	16,695
Downstream	1,186	2,243	3,429	823	1,701	2,524
Chemical	1,747	488	2,235	1,583	2,188	3,771
Other	65	-	65	90	-	90
<b>Total</b>	<b>10,668</b>	<b>15,255</b>	<b>25,923</b>	<b>6,212</b>	<b>16,868</b>	<b>23,080</b>

(1) Exploration expenses included.

Capital and exploration expenditures in 2018 were \$25.9 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 approximately \$30 billion in 2019. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of \$20.2 billion in 2018 was up 21 percent from 2017. Investments in 2018 included growth in the U.S. Permian Basin, acreage acquisitions in Brazil and global development projects. Development projects typically take several years from the time of recording proved undeveloped reserves to the start of production and can exceed five years for large and complex projects. The percentage of proved developed reserves was 68 percent of total proved reserves at year end 2018, and has been over 60 percent for the last ten years.

Capital investments in the Downstream totaled \$3.4 billion in 2018, an increase of \$0.9 billion from 2017, reflecting global project spending and a lubricants acquisition in Indonesia. Chemical capital expenditures of \$2.2 billion, decreased \$1.5 billion, representing investments in growth projects offset by the 2017 acquisition of a large-scale aromatics plant in Singapore.

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

	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars)</i>		
Income taxes	9,532	(1,174)	(406)
<i>Effective income tax rate</i>	<i>37%</i>	<i>5%</i>	<i>13%</i>
Total other taxes and duties	35,230	32,459	31,375
Total	44,762	31,285	30,969

**2018**

Total taxes on the Corporation's income statement were \$44.8 billion in 2018, an increase of \$13.5 billion from 2017. Income tax expense, both current and deferred, was \$9.5 billion compared to a credit of \$1.2 billion in 2017. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 37 percent compared to 5 percent. The increase principally reflects the absence of the impact of U.S. tax reform in the prior year. Total other taxes and duties of \$35.2 billion in 2018 increased \$2.8 billion.

**2017**

Total taxes on the Corporation's income statement were \$31.3 billion in 2017, an increase of \$0.3 billion from 2016. Income tax expense, both current and deferred, was a credit of \$1.2 billion compared to a credit of \$0.4 billion in 2016, with the U.S. tax reform impact of \$5.9 billion partially offset by higher 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 5 percent compared to 13 percent in the prior year due primarily to the impact of U.S. tax reform. Total other taxes and duties of \$32.5 billion in 2017 increased \$1.1 billion.

**U.S. Tax Reform**

Following the December 22, 2017, enactment of the U.S. Tax Cuts and Jobs Act, in accordance with Accounting Standard Codification Topic 740 (Income Taxes) and following the guidance outlined in the SEC Staff Accounting Bulletin No. 118, the Corporation included a \$5,942 million credit in its 2017 results, representing a reasonable estimate of the income tax effects of the changes in tax law and tax rate. The Corporation's results for 2018 include a \$291 million tax credit, mainly in the Non-U.S. Upstream, reflecting an updated estimate of the impact of U.S. tax reform including clarifications provided in proposed transition tax regulations issued by the U.S. Treasury in 2018. The Corporation has completed its accounting for the enactment-date income tax effects of the U.S. Tax Cuts and Jobs Act in accordance with Accounting Standard Codification Topic 740 (Income Taxes).

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

### ENVIRONMENTAL MATTERS

#### Environmental Expenditures

	<b>2018</b>	<b>2017</b>
	<i>(millions of dollars)</i>	
Capital expenditures	1,294	1,321
Other expenditures	3,558	3,349
Total	4,852	4,670

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 2018 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were \$4.9 billion, of which \$3.6 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately \$5.7 billion in 2019 and 2020. 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 2018 for environmental liabilities were \$330 million (\$302 million in 2017) and the balance sheet reflects liabilities of \$875 million as of December 31, 2018, and \$872 million as of December 31, 2017.

### MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

<b>Worldwide Average Realizations (1)</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
Crude oil and NGL (\$ per barrel)	62.79	48.91	38.15
Natural gas (\$ per thousand cubic feet)	3.87	3.04	2.25



*(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 \$450 million annual after-tax effect on Upstream consolidated plus equity company earnings, excluding the impact of derivatives. Similarly, a \$0.10 per thousand cubic feet change in the worldwide average gas realization would have approximately a \$165 million annual after-tax effect on Upstream consolidated plus equity company earnings, excluding the impact of derivatives. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, results of trading activities, 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.

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

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 commodity prices, currency rates and interest rates. In addition, the Corporation uses commodity-based contracts, including derivatives, to manage commodity price risk and for trading purposes. The Corporation's commodity derivatives are not accounted for under hedge accounting. At times, the Corporation also enters into forward currency and interest rate derivatives, none of which are material to the Corporation's financial position as of December 31, 2018 and 2017, or results of operations for the years ended 2018, 2017 and 2016. 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. No material market or credit risks to the Corporation's financial position, results of operations or liquidity exist as a result of the derivatives described in Note 13. 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. Fluctuations in exchange rates are often offsetting and the impacts on ExxonMobil's geographically and functionally diverse operations are varied. 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. Prices for services and materials continue to evolve in response to constant changes in commodity markets and industry activities, impacting operating and capital costs. The Corporation monitors market trends and works to minimize costs in all commodity price environments through its economies of scale in global procurement and its efficient project management practices.

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

### RECENTLY ISSUED ACCOUNTING STANDARDS

Effective January 1, 2019, the Corporation adopted the Financial Accounting Standards Board's Standard, *Leases (Topic 842)*, as amended. The standard requires all leases to be recorded on the balance sheet as a right of use asset and a lease liability. The Corporation used a transition method that applies the new lease standard at January 1, 2019, and recognizes any cumulative-effect adjustments to the opening balance of 2019 retained earnings. The Corporation applied a policy election to exclude short-term leases from balance sheet recognition and also elected certain practical expedients at adoption. As permitted under these expedients the Corporation did not reassess whether existing contracts are or contain leases, the lease classification for any existing leases, initial direct costs for any existing lease and whether existing land easements and rights of way, that were not previously accounted for as leases, are or contain a lease. At January 1, 2019, the operating lease liability is estimated to be in the range of \$3.3 billion and the operating lease right of use asset is estimated to be in the range of \$4.3 billion, including about \$1.0 billion related to prepaid leases. The cumulative effect adjustment is expected to be de minimis.

### CRITICAL ACCOUNTING ESTIMATES

The Corporation's accounting and financial reporting fairly reflect its integrated business model involving exploration for, and production of, crude oil and natural gas and manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty 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 assessments 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 68 percent of total proved reserves at year-end 2018 (including both consolidated and equity company reserves), an increase from 66 percent in 2017, 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, government policy, consumer preferences 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.

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

### 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 may be 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 substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes. The effect of this approach on the Corporation's 2018 depreciation expense versus 2017 was immaterial.

### Impairment

The Corporation tests assets or groups of assets for recoverability on an ongoing basis whenever events or changes in 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.

Asset valuation analyses performed as part of its asset management program and other profitability reviews assist the Corporation in assessing whether events or changes in circumstances indicate 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 believes that prices over the long term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments and technology and efficiency advancements. OPEC investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities and levels of prosperity. 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 to its long-term oil price, natural gas price or margin ranges, the Corporation may consider that situation, in conjunction with other events or changes in circumstances such as a history of operating losses, an indicator of potential impairment for certain assets.

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

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 changes in circumstances indicate that the carrying value of an asset 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 capital allocations, 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 estimated 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.

The Corporation has a robust process to monitor for indicators of potential impairment across its asset groups throughout the year. This process is aligned with the requirements of ASC 360 and relies in part on the Corporation's planning and budgeting cycle. In 2018, the Corporation identified a number of situations where events or changes in circumstances indicated that the carrying value of certain long-lived assets, mainly in North America, may not be recoverable. Accordingly, impairment assessments were performed which indicated that certain asset groups assessed have future undiscounted cash flow estimates that do not recover their carrying values. The Corporation's 2018 results include after-tax charges of \$0.5 billion to reduce the carrying value of those assets to fair value.

The assessment of fair values required the use of Level 3 inputs and assumptions that are based upon the views of a likely market participant. 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 6 percent to 8 percent depending on the characteristics of the asset group, and comparable market transactions. Factors which could put further assets at risk of impairment in the future include reductions in the Corporation's long-term price outlooks, changes in the allocation of capital, and operating cost increases which exceed the pace of efficiencies or the pace of oil and natural gas price increases. However, 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.



### **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.

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

### Consolidations

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 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 2018 was 6 percent. The 10 year and 20 year actual returns on U.S. pension plan assets were 8 percent and 7 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 \$150 million before tax.

Differences between actual returns on fund assets and the long-term expected return are not recognized in pension expense in the 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.

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

### **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 U.S. 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, 2018.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2018, as stated in their report included in the Financial Section of this report.

Darren W. Woods

Chief Executive Officer

Andrew P. Swiger

Senior Vice President

(Principal Financial Officer)

David S. Rosenthal

Vice President and Controller

(Principal Accounting Officer)

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of Exxon Mobil Corporation

***Opinions on the Financial Statements and Internal Control over Financial Reporting***

We have audited the accompanying consolidated balance sheets of Exxon Mobil Corporation and its subsidiaries (the "Corporation") as of December 31, 2018 and 2017, and the related consolidated statements of income, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Corporation's internal control over financial reporting as of December 31, 2018 based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Corporation as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 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, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

***Basis for Opinions***

The Corporation's management is responsible for these consolidated 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 the Corporation's consolidated financial statements and on the Corporation's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.



**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

*Definition and Limitations of Internal Control over Financial Reporting*

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 27, 2019

We have served as the Corporation's auditor since 1934.

**CONSOLIDATED STATEMENT OF INCOME**

	<b>Note Reference Number</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
		<i>(millions of dollars)</i>		
Revenues and other income				
Sales and other operating revenue		279,332	237,162	200,628
Income from equity affiliates	7	7,355	5,380	4,806
Other income		3,525	1,821	2,680
Total revenues and other income		290,212	244,363	208,114
Costs and other deductions				
Crude oil and product purchases		156,172	128,217	104,171
Production and manufacturing expenses		36,682	32,690	30,448
Selling, general and administrative expenses		11,480	10,649	10,443
Depreciation and depletion	9	18,745	19,893	22,308
Exploration expenses, including dry holes		1,466	1,790	1,467
Non-service pension and postretirement benefit expense	2, 17	1,285	1,745	1,835
Interest expense		766	601	453
Other taxes and duties	19	32,663	30,104	29,020
Total costs and other deductions		259,259	225,689	200,145
Income before income taxes		30,953	18,674	7,969
Income taxes	19	9,532	(1,174)	(406)
Net income including noncontrolling interests		21,421	19,848	8,375
Net income attributable to noncontrolling interests		581	138	535
Net income attributable to ExxonMobil		20,840	19,710	7,840
Earnings per common share <i>(dollars)</i>	12	4.88	4.63	1.88
Earnings per common share - assuming dilution <i>(dollars)</i>	12	4.88	4.63	1.88

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

**CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME**

	<b>2018</b>	<b>2017</b>	<b>2016</b>
	<i>(millions of dollars)</i>		
Net income including noncontrolling interests	21,421	19,848	8,375
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	(5,077)	5,352	(174)
Adjustment for foreign exchange translation (gain)/loss included in net income	196	234	-
Postretirement benefits reserves adjustment (excluding amortization)	280	(219)	493
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	931	1,165	1,086
Total other comprehensive income	(3,670)	6,532	1,405
Comprehensive income including noncontrolling interests	17,751	26,380	9,780
Comprehensive income attributable to noncontrolling interests	174	693	668
Comprehensive income attributable to ExxonMobil	17,577	25,687	9,112

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

**CONSOLIDATED BALANCE SHEET**

	<b>Note Reference Number</b>	<b>Dec. 31 2018</b>	<b>Dec. 31 2017</b>
<i>(millions of dollars)</i>			
Assets			
Current assets			
Cash and cash equivalents		3,042	3,177
Notes and accounts receivable, less estimated doubtful amounts	6	24,701	25,597
Inventories			
Crude oil, products and merchandise	3	14,803	12,871
Materials and supplies		4,155	4,121
Other current assets		1,272	1,368
Total current assets		47,973	47,134
Investments, advances and long-term receivables	8	40,790	39,160
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	247,101	252,630
Other assets, including intangibles, net			