2021

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, 2021

or

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

For the transition period from _______ to _______

Commission File Number 1-2256

Exxon Mobil Corporation

(Exact name of registrant as specified in its charter)

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

5959 Las Colinas Boulevard, Irving, Texas 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 940-6000

(Registrant's telephone number, including area code)

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

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, without par value	**XOM**	**New York Stock Exchange**
0.142% Notes due 2024	**XOM24B**	**New York Stock Exchange**
0.524% Notes due 2028	**XOM28**	**New York Stock Exchange**
0.835% Notes due 2032	**XOM32**	**New York Stock Exchange**
1.408% Notes due 2039	**XOM39A**	**New York Stock Exchange**

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

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

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2021, the last business day of the registrant’s most recently completed second fiscal quarter, based on the closing price on that date of $63.08 on the New York Stock Exchange composite tape, was in excess of $267 billion.

Class	**Outstanding as of January 31, 2022**
Common stock, without par value	**4,233,592,429**

Documents Incorporated by Reference: Proxy Statement for the 2022 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2021

TABLE OF CONTENTS

PART I

PART II

PART III

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. Our principal business involves exploration for, and production of, crude oil and natural gas; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen and biofuels. 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, both within the industries and also with other industries in supplying the energy, fuel, and chemical needs of industrial and individual consumers. Certain industry participants, including ExxonMobil, are expanding investments in lower-emission energy and emission-reduction services and technologies. 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: “Management's Discussion and Analysis of Financial Condition and Results of Operations: Business Results” and “Note 18: Disclosures about Segments and Related 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 over 8 thousand active patents worldwide at the end of 2021. For technology licensed to third parties, revenues totaled approximately $66 million in 2021. 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.

ExxonMobil operates in a highly complex, competitive, and changing global energy business environment where decisions and risks play out over time horizons that are often decades in length. This long-term orientation underpins the Corporation's philosophy on talent development.

Talent development begins with recruiting exceptional candidates and continues with individually planned experiences and training designed to facilitate broad development and a deep understanding of our business across the business cycle. Our career-oriented approach to talent development results in strong retention and an average length of service of 30 years for our career employees. Compensation, benefits, and workplace programs support the Corporation's talent management approach, and are designed to attract and retain employees for a career through compensation that is market competitive, long-term oriented, and highly differentiated by individual performance.

Over 60 percent of our global employee workforce is from outside the U.S., and over the past decade 39 percent of our global hires for management, professional and technical positions were female and 35 percent of our U.S. hires for management, professional and technical positions were minorities. With over 160 nationalities represented in the company, we encourage and respect diversity of thought, ideas, and perspective from our workforce. We consider and monitor diversity through all stages of employment, including recruitment, training, and development of our employees. We also work closely with the communities where we operate to identify and invest in initiatives that help support local needs, including local talent and skill development.

The number of regular employees was 63 thousand, 72 thousand, and 75 thousand at years ended 2021, 2020, and 2019, 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.

As discussed in item 1A. Risk Factors in this report, compliance with existing and potential future government regulations, including taxes, environmental regulations, and other government regulations and policies that directly or indirectly affect the production and sale of our products, may have material effects on the capital expenditures, earnings, and competitive position of ExxonMobil. With respect to the environment, throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water, and ground, including, but not limited to, compliance with environmental regulations. 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 2021 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.6 billion, of which $3.4 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $5.3 billion in 2022, with capital expenditures expected to account for approximately 30 percent of the total. Costs for 2023 are anticipated to be higher as the Low Carbon Solutions business matures and the Corporation progresses its emission-reduction plans.

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

ExxonMobil maintains a website at exxonmobil.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available through our website as soon as reasonably practical after we electronically file or furnish the reports to the Securities and Exchange Commission (SEC). Also available on the Corporation's website are the company's Corporate Governance Guidelines, Code of Ethics and Business Conduct, and additional policies as well as the charters of the audit, compensation, and other 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, and the pursuit of lower-emission business opportunities. 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 or product. 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 regulation or austerity programs, trade tariffs or broader breakdowns in global trade, security or public health issues and responses, 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.

COVID-19. The initial phase of the COVID-19 pandemic caused conditions of demand reduction and oversupply to develop rapidly and resulted in significant decreases in commodity prices and margins. ExxonMobil's future business results, including cash flows and financing needs, will be affected by the scope and severity of current and future COVID outbreaks; actions taken by governments and others to address the pandemic and the effects of those actions on national and global economies and markets; changes in consumer behavior that affect demand for our products; and the effectiveness of the Corporation's own responsive actions to protect the safety and well-being of our people.

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, or government policy support for, alternative energy sources; changes in technology that alter fuel choices, such as technological advances in energy storage that make wind and solar more competitive for power generation; changes in consumer preferences for our products, including consumer demand for alternative fueled or electric transportation or alternatives to plastic products; and broad-based changes in personal income levels. See also "Climate Change and the Energy Transition" below.

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 tends 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 the level of and adherence by participating countries to production quotas established by OPEC or "OPEC+" and other agreements among sovereigns, government policies, including actions intended to reduce greenhouse gas emissions, that restrict oil and gas production or increase associated costs, 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. Market factors may also result in losses from commodity derivatives and other instruments we use to hedge price exposures or for trading purposes.

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, including by restricting leasing or permitting activities, or may place resources off-limits from development altogether. Restrictions on production of oil and gas could increase to the extent governments view such measures as a viable approach for pursuing national and global energy and climate policies. 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) and changes in policy 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 affecting offshore drilling operations, water use, methane emissions, hydraulic fracturing, or use of new or recycled plastics);
- actions by policy-makers, regulators, or other actors to delay or deny necessary licenses and permits, restrict the availability of oil and gas leases or the transportation of our products, or otherwise require changes in the company's business or strategy that could result in reduced returns;
- 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; by government enforcement proceedings alleging non-compliance with applicable laws or regulations; or by state and local government actors as well as private plaintiffs acting in parallel that attempt to use the legal system to promote public policy agendas (including seeking to reduce the production and sale of hydrocarbon products though litigation targeting the company or other industry participants), gain political notoriety, or obtain monetary awards from the company.

Security concerns. Successful operation of particular facilities or projects may be disrupted by civil unrest, acts of sabotage or terrorism, cybersecurity attacks, the application of national security laws or policies that result in restricting our ability to do business in a particular jurisdiction, 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 the Energy Transition

Net-zero scenarios. Driven by 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 including emissions from the production and use of oil and gas and their products. These actions are being taken both independently by national and regional governments and within the framework of United Nations Conference of the Parties summits under which many countries of the world have endorsed objectives to reduce the atmospheric concentration of CO_2 over the coming decades, with an ambition ultimately to achieve “net-zero.” Net-zero means that emissions of greenhouse gases from human activities would be balanced by actions that remove such gases from the atmosphere. Expectations for transition of the world’s energy system to lower emission sources and ultimately net-zero derive from hypothetical scenarios that reflect many assumptions about the future and reflect substantial uncertainties. The company’s objective to lead in the energy transition, including the company’s announced ambition ultimately to achieve net-zero with respect to emissions from operations where ExxonMobil is the operator, carries risks that the transition, including underlying technologies, policies, and markets as discussed in more detail below, will not develop at the pace or in the manner expected by current net-zero scenarios. The success of our strategy for the energy transition will also depend on our ability to recognize key signposts of change in the global energy system on a timely basis, and our corresponding ability to direct investment to the technologies and businesses, at the appropriate stage of development, to best capitalize on our competitive strengths.

Greenhouse gas restrictions. Government actions intended to reduce greenhouse gas emissions include adoption of cap and trade regimes, carbon taxes, trade tariffs, minimum renewable usage requirements, restrictive permitting, increased mileage and other efficiency standards, mandates for sales of electric vehicles, mandates for use of specific fuels or technologies, and other incentives or mandates designed to support transitioning to lower-emission energy sources. Political and other actors and their agents also increasingly seek to advance climate change objectives indirectly, such as by seeking to reduce the availability or increase the cost of financing and investment in the oil and gas sector and taking actions intended to promote changes in business strategy for oil and gas companies. Depending on how policies are formulated and applied, such policies could negatively affect our investment returns, make our hydrocarbon-based products more expensive or less competitive, lengthen project implementation times, and reduce demand for hydrocarbons, as well as shift hydrocarbon demand toward relatively lower-carbon alternatives. Current and pending greenhouse gas regulations or policies may also increase our compliance costs, such as for monitoring or sequestering emissions.

Technology and low carbon solutions. Achieving societal ambitions to reduce greenhouse gas emissions and ultimately achieve net-zero will require new technologies to reduce the cost and increase the scalability of alternative energy sources, as well as technologies such as carbon capture and storage (CCS). CCS technologies, focused initially on capturing and sequestering CO_2 emissions from high-intensity industrial activities, can assist in meeting society’s objective to mitigate atmospheric greenhouse gas levels while also helping ensure the availability of the reliable and affordable energy the world requires. ExxonMobil has established a Low Carbon Solutions (LCS) business unit to advance the development and deployment of these technologies and projects, including CCS, hydrogen and advanced biofuels, breakthrough energy efficiency processes, advanced energy-saving materials, and other technologies. The company’s efforts include both in-house research and development and collaborative efforts with leading universities as well as commercial partners involved in advanced lower-emission energy technologies.

Our future results and ability to grow our LCS business and succeed through the energy transition will depend in part on the success of these research and collaboration 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.

Policy and market development. The scale of the world's energy system means that, in addition to developments in technology as discussed above, a successful energy transition will require appropriate support from governments and private participants throughout the global economy. Our ability to develop and deploy CCS and other lower emission energy technologies at commercial scale, and the growth and future returns of LCS and other emerging businesses in which we invest, will depend in part on the continued development of supportive government policies and markets. Failure or delay of these policies or markets to materialize or be maintained could adversely impact these investments. Policy and other actions that result in restricting the availability of hydrocarbon products without commensurate reduction in demand may have unpredictable adverse effects, including increased commodity price volatility; periods of significantly higher commodity prices and resulting inflationary pressures; and local or regional energy shortages. Such effects in turn may depress economic growth or lead to rapid or conflicting shifts in policy by different actors, with resulting adverse effects on our businesses.

See also the discussion of “Supply and Demand,” “Government and Political Factors,” and “Operational and Other Factors” in this Item 1A.

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, as well as the future success of LCS and other emerging lower-emission investments, 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 start-up 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, products produced, and strategies to divest assets. We may not be able to divest assets at a price or on the timeline we contemplate in our strategies. Additionally, we may retain certain liabilities following a divestment and could be held liable for past use or for different liabilities than anticipated.

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 technology, 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, including successfully applying advances in the ability to process very large amounts of data to our businesses.

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 employ a comprehensive enterprise risk management system to identify and manage risk across our businesses. 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 we do not timely identify and mitigate applicable risks, or if our management systems and controls do not function as intended.

Cybersecurity. ExxonMobil is regularly subject to attempted cybersecurity disruptions from a variety of sources 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 or if our proprietary data is otherwise not protected, ExxonMobil as well as our customers, employees, or third parties could be adversely affected. We are also exposed to potential harm from cybersecurity events that may affect the operations of third-parties, including our partners, suppliers, service providers (including providers of cloud-hosting services for our data or applications), and customers. 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 availability and cost of coverage, which may not be economic, as well as 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 and as partners with other private firms. 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. As described in more detail above, our hydrocarbon-based energy products are also subject to growing and, in many cases, government-supported competition from alternative energy sources.

Reputation. Our reputation is an important corporate asset. Factors that could have a negative impact on our reputation include an operating incident or significant cybersecurity disruption; changes in consumer views concerning our products; a perception by investors or others that the Corporation is making insufficient progress with respect to our ambition to lead in the energy transition, or that pursuit of this ambition may result in allocation of capital to investments with reduced returns; and other adverse events such as those described in this Item 1A. Negative impacts on our reputation could in turn make it more difficult for us to compete successfully for new opportunities, obtain necessary regulatory approvals, obtain financing, attract talent, 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 2021

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. As a result of higher average prices in 2021, certain quantities of crude oil, bitumen, and natural gas that did not qualify as proved reserves in the prior year qualified as proved reserves at year-end 2021. Otherwise, no major discovery or other favorable or adverse event has occurred since December 31, 2021 that would cause a significant change in the estimated proved reserves as of that date.

	Crude Oil	Natural Gas Liquids	Bitumen	Synthetic Oil	Natural Gas	Oil-Equivalent Total All Products
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million bbls)*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,170	493	—	—	11,287	3,544
Canada/Other Americas *(1)*	262	6	2,635	326	574	3,325
Europe	3	—	—	—	377	66
Africa	304	26	—	—	315	382
Asia	2,096	58	—	—	2,527	2,575
Australia/Oceania	45	18	—	—	3,513	648
Total Consolidated	3,880	601	2,635	326	18,593	10,540
Equity Companies						
United States	127	6	—	—	117	153
Europe	10	—	—	—	339	66
Africa	—	—	—	—	—	—
Asia	322	152	—	—	6,017	1,477
Total Equity Company	459	158	—	—	6,473	1,696
Total Developed	4,339	759	2,635	326	25,066	12,236
Undeveloped						
Consolidated Subsidiaries						
United States	1,137	484	—	—	3,701	2,238
Canada/Other Americas *(1)*	507	1	259	112	345	937
Europe	—	—	—	—	6	1
Africa	31	—	—	—	2	31
Asia	941	47	—	—	1,166	1,182
Australia/Oceania	29	3	—	—	2,850	507
Total Consolidated	2,645	535	259	112	8,070	4,896
Equity Companies						
United States	28	—	—	—	23	32
Europe	—	—	—	—	69	12
Africa	5	—	—	—	806	139
Asia	419	112	—	—	4,141	1,221
Total Equity Company	452	112	—	—	5,039	1,404
Total Undeveloped	3,097	647	259	112	13,109	6,300
Total Proved Reserves	7,436	1,406	2,894	438	38,175	18,536

(1) Other Americas includes proved developed reserves of 106 million barrels of crude oil and 151 billion cubic feet of natural gas, as well as proved undeveloped reserves of 488 million barrels of crude oil and 233 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 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 crude 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 2021

Additions to ExxonMobil's proved reserves in 2021 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 seismic processing software, reservoir modeling and simulation software, and 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 and Resources 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 and Resources group has more than 30 years of experience in reservoir engineering and reserves assessment, has a degree in Engineering and served 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 15 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves under SEC guidelines. This group includes individuals who hold degrees in either Engineering or Geology.

The Global Reserves and Resources 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, commercial and market assessments, analysis of well and field performance, and long-standing approval guidelines. 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 geoscience and engineering professionals within the operating organization. In addition, changes to reserves estimates that exceed certain thresholds require further review and approval by the appropriate level of management within the operating organization before the changes may be made in the central database. Endorsement by the Global Reserves and Resources 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 2021, approximately 6.3 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 34 percent of the 18.5 GOEB reported in proved reserves. This compares to 5.0 GOEB of proved undeveloped reserves reported at the end of 2020. During the year, ExxonMobil conducted development activities that resulted in the transfer of approximately 0.5 GOEB from proved undeveloped to proved developed reserves by year end. The largest transfers were related to development activities in the United States. During 2021, extensions and discoveries, primarily in the United States, Brazil, and Guyana, resulted in an addition of approximately 1.3 GOEB of proved undeveloped reserves, along with an increase of approximately 0.6 GOEB due to revisions primarily in Asia and Canada.

Overall, investments of $8.0 billion were made by the Corporation during 2021 to progress the development of reported proved undeveloped reserves, including $7.8 billion for oil and gas producing activities, along with 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 $12.3 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 Australia, Canada, Kazakhstan, the United States, and the United Arab Emirates 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 crude 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 Australia, proved undeveloped reserves are associated with future compression for the Gorgon Jansz LNG project. In Canada, proved undeveloped reserves are related to Cold Lake operations. In Kazakhstan, the proved undeveloped reserves are related to the remainder of the Tengizchevroil joint venture development that includes a production license in the Tengiz - Korolev field complex. The Tengizchevroil joint venture is producing, and proved undeveloped reserves will continue to move to proved developed as approved development phases progress. In the United Arab Emirates, proved undeveloped reserves are associated with an approved development plan and continued drilling investment for the producing Upper Zakum field.

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.

	2021		2020		2019	
	(thousands of barrels daily)					
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries						
United States	482	195	481	154	461	131
Canada/Other Americas *(1)*	130	3	121	5	87	4
Europe	16	3	22	5	84	21
Africa	241	7	301	11	360	12
Asia	407	21	449	23	432	22
Australia/Oceania	28	15	29	15	30	15
Total Consolidated Subsidiaries	1,304	244	1,403	213	1,454	205
Equity Companies						
United States	43	1	49	1	52	2
Europe	3	—	3	—	3	—
Asia	207	60	208	62	232	62
Total Equity Companies	253	61	260	63	287	64
Total crude oil and natural gas liquids production	1,557	305	1,663	276	1,741	269
Bitumen production						
Consolidated Subsidiaries						
Canada/Other Americas	365		342		311	
Synthetic oil production						
Consolidated Subsidiaries						
Canada/Other Americas	62		68		65	
Total liquids production	2,289		2,349		2,386	
	(millions of cubic feet daily)					
Natural gas production available for sale						
Consolidated Subsidiaries						
United States	2,724		2,668		2,756	
Canada/Other Americas *(1)*	195		277		258	
Europe	377		447		808	
Africa	43		9		7	
Asia	807		872		851	
Australia/Oceania	1,280		1,219		1,319	
Total Consolidated Subsidiaries	5,426		5,492		5,999	
Equity Companies						
United States	22		23		22	
Europe	431		342		649	
Asia	2,658		2,614		2,724	
Total Equity Companies	3,111		2,979		3,395	
Total natural gas production available for sale	8,537		8,471		9,394	
	(thousands of oil-equivalent barrels daily)					
Oil-equivalent production	3,712		3,761		3,952	

(1) Other Americas includes crude oil production for 2021, 2020 and 2019 of 48 thousand, 29 thousand, and 2 thousand barrels daily, respectively; and natural gas production available for sale for 2021, 2020 and 2019 of 36 million, 45 million, and 36 million cubic feet daily, respectively.

B. Production Prices and Production Costs

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

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2021				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	65.03	68.56	66.20	70.21	67.28	69.00	67.14
NGL, per barrel	32.24	30.51	42.31	54.57	32.62	43.07	33.65
Natural gas, per thousand cubic feet	3.02	2.92	11.83	1.67	2.11	6.64	4.33
Bitumen, per barrel	—	44.26	—	—	—	—	44.26
Synthetic oil, per barrel	—	64.73	—	—	—	—	64.73
Average production costs, per oil-equivalent barrel - total	8.33	22.47	25.31	18.92	7.16	5.14	12.15
Average production costs, per barrel - bitumen	—	22.69	—	—	—	—	22.69
Average production costs, per barrel - synthetic oil	—	48.87	—	—	—	—	48.87
Equity Companies							
Average production prices							
Crude oil, per barrel	67.06	—	62.60	—	65.85	—	66.01
NGL, per barrel	29.94	—	—	—	52.14	—	51.64
Natural gas, per thousand cubic feet	3.11	—	8.19	—	6.54	—	6.74
Average production costs, per oil-equivalent barrel - total	30.51	—	38.82	—	1.59	—	6.67
Total							
Average production prices							
Crude oil, per barrel	65.20	68.56	65.54	70.21	66.80	69.00	66.96
NGL, per barrel	32.23	30.51	42.31	54.57	47.10	43.07	37.27
Natural gas, per thousand cubic feet	3.02	2.92	9.89	1.67	5.50	6.64	5.21
Bitumen, per barrel	—	44.26	—	—	—	—	44.26
Synthetic oil, per barrel	—	64.73	—	—	—	—	64.73
Average production costs, per oil-equivalent barrel - total	9.24	22.47	31.79	19.04	4.06	5.14	10.92
Average production costs, per barrel - bitumen	—	22.69	—	—	—	—	22.69
Average production costs, per barrel - synthetic oil	—	48.87	—	—	—	—	48.87
During 2020							
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	34.97	37.26	41.39	42.27	39.39	36.67	38.31
NGL, per barrel	13.83	10.34	20.11	21.32	21.37	27.92	16.05
Natural gas, per thousand cubic feet	0.98	1.56	3.13	1.24	1.49	4.34	2.01
Bitumen, per barrel	—	17.71	—	—	—	—	17.71
Synthetic oil, per barrel	—	37.32	—	—	—	—	37.32
Average production costs, per oil-equivalent barrel - total	9.82	18.40	21.22	16.67	6.50	5.35	11.57
Average production costs, per barrel - bitumen	—	19.22	—	—	—	—	19.22
Average production costs, per barrel - synthetic oil	—	33.61	—	—	—	—	33.61
Equity Companies							
Average production prices							
Crude oil, per barrel	39.10	—	38.95	—	35.18	—	35.97

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2019				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	54.41	59.39	63.59	65.64	64.14	61.08	61.04
NGL, per barrel	18.94	16.59	30.56	41.41	24.64	30.55	22.85
Natural gas, per thousand cubic feet	1.54	1.44	4.50	1.49	2.07	6.26	3.05
Bitumen, per barrel	—	36.25	—	—	—	—	36.25
Synthetic oil, per barrel	—	56.18	—	—	—	—	56.18
Average production costs, per oil-equivalent barrel - total	12.25	23.41	13.69	17.51	7.34	6.60	13.43
Average production costs, per barrel - bitumen	—	24.18	—	—	—	—	24.18
Average production costs, per barrel - synthetic oil	—	40.38	—	—	—	—	40.38
Equity Companies							
Average production prices							
Crude oil, per barrel	60.95	—	58.72	—	58.74	—	59.15
NGL, per barrel	15.63	—	—	—	36.28	—	35.76
Natural gas, per thousand cubic feet	1.75	—	5.01	—	5.24	—	5.17
Average production costs, per oil-equivalent barrel - total	25.70	—	14.04	—	2.03	—	5.00
Total							
Average production prices							
Crude oil, per barrel	55.08	59.39	63.41	65.64	62.27	61.08	60.73
NGL, per barrel	18.90	16.59	30.56	41.41	33.23	30.55	25.89
Natural gas, per thousand cubic feet	1.54	1.44	4.73	1.49	4.49	6.26	3.82
Bitumen, per barrel	—	36.25	—	—	—	—	36.25
Synthetic oil, per barrel	—	56.18	—	—	—	—	56.18
Average production costs, per oil-equivalent barrel - total	12.95	23.41	13.80	17.56	4.39	6.60	11.48
Average production costs, per barrel - bitumen	—	24.18	—	—	—	—	24.18
Average production costs, per barrel - synthetic oil	—	40.38	—	—	—	—	40.38

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

	2021	2020	2019
Net Productive Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	1	4	3
Canada/Other Americas	5	2	6
Europe	—	—	1
Africa	—	1	—
Asia	—	—	—
Australia/Oceania	—	—	1
Total Consolidated Subsidiaries	6	7	11
Equity Companies			
United States	—	—	—
Europe	—	—	—
Africa	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total productive exploratory wells drilled	6	7	11
Net Dry Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	1	—	—
Canada/Other Americas	3	1	1
Europe	—	—	1
Africa	—	—	—
Asia	—	1	—
Australia/Oceania	—	—	1
Total Consolidated Subsidiaries	4	2	3
Equity Companies			
United States	—	—	—
Europe	—	—	—
Africa	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total dry exploratory wells drilled	4	2	3

	2021	2020	2019
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
United States	433	412	618
Canada/Other Americas	28	36	49
Europe	1	2	3
Africa	1	2	4
Asia	4	15	12
Australia/Oceania	—	4	—
Total Consolidated Subsidiaries	467	471	686
Equity Companies			
United States	13	60	199
Europe	1	1	—
Africa	1	—	—
Asia	5	5	9
Total Equity Companies	20	66	208
Total productive development wells drilled	487	537	894
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	4	6	8
Canada/Other Americas	—	—	—
Europe	—	—	—
Africa	—	—	1
Asia	—	—	—
Australia/Oceania	—	1	—
Total Consolidated Subsidiaries	4	7	9
Equity Companies			
United States	—	—	—
Europe	—	—	—
Africa	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total dry development wells drilled	4	7	9
Total number of net wells drilled	501	553	917

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 2021, the company's share of net production of synthetic crude oil was about 62 thousand barrels per day and share of net acreage was about 55 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 2021, average net production at Kearl was about 251 thousand barrels per day.

During 2021, approximately 2.4 billion barrels of bitumen at Kearl were added to proved reserves primarily as a result of an improved SEC price basis versus 2020.

5. Present Activities

A. Wells Drilling

	Year-End 2021		Year-End 2020	
	Gross	Net	Gross	Net
Wells Drilling				
Consolidated Subsidiaries				
United States	1,059	588	1,206	741
Canada/Other Americas	44	33	38	29
Europe	2	1	13	6
Africa	11	2	14	3
Asia	11	3	14	4
Australia/Oceania	—	—	—	—
Total Consolidated Subsidiaries	1,127	627	1,285	783
Equity Companies				
United States	12	—	3	1
Europe	—	—	1	1
Africa	—	—	6	1
Asia	2	1	2	1
Total Equity Companies	14	1	12	4
Total gross and net wells drilling	1,141	628	1,297	787

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2021 acreage holdings totaled 10.5 million net acres, of which 0.3 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska. Development activities continued on the Golden Pass liquefied natural gas export project.

During the year, a total of 449.4 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.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2021 was 0.3 million acres. A total of 0.8 net exploration and development wells were completed during the year.

Participation in Alaska production and development continued with a total of 1.1 net development wells completed.

CANADA / OTHER AMERICAS

Canada

Oil and Gas Operations: ExxonMobil's year-end 2021 acreage holdings totaled 6.7 million net acres, of which 3.9 million net acres were offshore. A total of 3.7 net development wells were completed during the year.

In Situ Bitumen Operations: ExxonMobil's year-end 2021 in situ bitumen acreage holdings totaled 0.6 million net onshore acres. A total of 12 net development wells at Cold Lake were completed during the year.

Argentina

ExxonMobil's net acreage totaled 2.9 million acres, of which 2.6 million net acres were offshore at year-end 2021. During the year, a total of 8.1 net development wells were completed.

Brazil

ExxonMobil's net acreage totaled 2.6 million offshore acres at year-end 2021. During the year, a total of 1.4 net exploration wells were completed. The Bacalhau Phase 1 project was funded in 2021.

Guyana

ExxonMobil's net acreage totaled 4.6 million offshore acres at year-end 2021. During the year, a total of 11 net exploration and development wells were completed. Development activities continued on the Liza Phase 2 and Payara projects.

EUROPE

Germany

ExxonMobil's net acreage totaled 1.6 million onshore acres at year-end 2021. During the year, a total of 0.3 net development well was completed.

Netherlands

ExxonMobil's net interest in licenses totaled 1.4 million acres, of which 1.0 million acres were onshore at year-end 2021. During the year, a total of 0.5 net development well was completed. In 2021, the Dutch Government further reduced Groningen gas extraction. The expectation is that Groningen will cease regular production in 2022.

United Kingdom

ExxonMobil's net interest in licenses totaled 0.1 million offshore acres at year-end 2021. During the year, a total of 0.4 net development well was completed.

AFRICA

Angola

ExxonMobil’s net acreage totaled 3.0 million acres, of which 2.9 million net acres were offshore at year-end 2021. During the year, a total of 1.1 net development wells were completed.

Chad

ExxonMobil’s net acreage totaled 46 thousand onshore acres at year-end 2021. In 2021, ExxonMobil entered into an agreement to divest its assets in Chad. The transaction is expected to close in 2022.

Equatorial Guinea

ExxonMobil’s net acreage totaled 0.1 million offshore acres at year-end 2021. In 2021, ExxonMobil relinquished 0.4 million net offshore acres.

Mozambique

ExxonMobil’s net acreage totaled 1.8 million offshore acres at year-end 2021. During the year, a total of 1.5 net development wells were completed. Development activities continued on the Coral South Floating LNG project.

Nigeria

ExxonMobil’s net acreage totaled 0.9 million offshore acres at year-end 2021.

ASIA

Azerbaijan

ExxonMobil's net acreage totaled 7 thousand offshore acres at year-end 2021. During the year, a total of 0.7 net development wells were completed.

Indonesia

ExxonMobil’s net acreage totaled 0.1 million onshore acres at year-end 2021.

Iraq

ExxonMobil’s net acreage totaled 36 thousand onshore acres at year-end 2021. Oil field rehabilitation activities continued during 2021 and across the life of this project will include drilling of new wells; working over of existing wells; and optimization, debottlenecking and expansion of facilities.

Kazakhstan

ExxonMobil’s net acreage totaled 0.3 million acres, of which 0.2 million net acres were offshore at year-end 2021. During the year, a total of 2 net development wells were completed. Development activities continued on the Tengiz Expansion project.

Malaysia

ExxonMobil’s interests in production sharing contracts covered 0.2 million net acres offshore at year-end 2021.

Qatar

Through our joint ventures with Qatar Energy, ExxonMobil’s net acreage totaled 65 thousand acres offshore at year-end 2021. ExxonMobil participated in 62.2 million tonnes per year gross liquefied natural gas capacity and 3.4 billion cubic feet per day of flowing gas capacity at year-end. During the year, a total of 4.8 net development wells were completed. The North Field Production Sustainment Integrated Drilling and Looping project was funded in 2021. Effective January 1, 2022, ExxonMobil no longer participates in the Qatar Liquefied Gas Company Limited

(QG1) venture, representing 3.6 thousand net acres and 9.9 million tonnes per year gross liquefied natural gas capacity.

Russia

ExxonMobil's net acreage holdings in Sakhalin totaled 85 thousand offshore acres at year-end 2021. During the year, a total of 0.9 net development wells were completed.

Thailand

ExxonMobil's net onshore acreage in Thailand concessions totaled 16 thousand acres at year-end 2021. During the year, a total of 0.2 development wells were completed.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2021. During the year, a total of 0.6 net development wells were completed. Development activities continued on the Upper Zakum 1 MBD Sustainment project.

AUSTRALIA / OCEANIA

Australia

ExxonMobil's net acreage totaled 1.8 million acres offshore and 10 thousand acres onshore at year-end 2021.

The co-venturer-operated Gorgon Jansz liquefied natural gas (LNG) development consists of a subsea infrastructure for offshore production and transportation of the gas, a 15.6 million tonnes per year LNG facility and a 280 million cubic feet per day domestic gas plant located on Barrow Island, Western Australia. The Jansz-Io Compression project was funded in 2021. Development activities continued on the Gorgon Stage 2 project during the year.

Papua New Guinea

ExxonMobil's net acreage totaled 3.4 million acres, of which 1.2 million net acres were offshore at year-end 2021. In 2021, ExxonMobil relinquished 2.1 million net offshore acres. 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.

WORLDWIDE EXPLORATION

At year-end 2021, 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 18.3 million net acres were held at year-end 2021.

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 28 million barrels of oil and 2,500 billion cubic feet of natural gas for the period from 2022 through 2024. 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 purchases on the open market as necessary.

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

A. Gross and Net Productive Wells

	Year-End 2021				Year-End 2020			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	19,401	7,566	18,670	10,773	19,631	7,878	20,480	12,195
Canada/Other Americas	4,656	4,548	3,209	1,247	4,754	4,644	3,276	1,275
Europe	439	116	441	207	559	126	487	221
Africa	1,102	416	24	10	1,141	432	26	10
Asia	1,038	333	137	80	974	310	132	78
Australia/Oceania	522	99	94	40	540	102	90	38
Total Consolidated Subsidiaries	27,158	13,078	22,575	12,357	27,599	13,492	24,491	13,817
Equity Companies								
United States	12,108	4,793	3,355	333	12,368	4,851	4,223	417
Europe	57	20	547	171	57	20	552	172
Asia	225	56	168	35	217	54	157	32
Total Equity Companies	12,390	4,869	4,070	539	12,642	4,925	4,932	621
Total gross and net productive wells	39,548	17,947	26,645	12,896	40,241	18,417	29,423	14,438

There were 23,645 gross and 20,528 net operated wells at year-end 2021 and 25,595 gross and 22,239 net operated wells at year-end 2020. The number of wells with multiple completions was 1,082 gross in 2021 and 1,067 gross in 2020.

B. Gross and Net Developed Acreage

	Year-End 2021		Year-End 2020	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	12,180	7,503	12,834	7,971
Canada/ Other Americas *(1)*	2,905	2,075	2,944	2,071
Europe	1,980	1,078	2,231	1,189
Africa	2,409	818	2,409	818
Asia	1,929	557	1,938	561
Australia/ Oceania	3,242	1,067	3,262	1,068
Total Consolidated Subsidiaries	24,645	13,098	25,618	13,678
Equity Companies				
United States	687	163	928	208
Europe	3,646	1,116	3,667	1,118
Asia	701	160	701	160
Total Equity Companies	5,034	1,439	5,296	1,486
Total gross and net developed acreage	29,679	14,537	30,914	15,164

(1) Includes developed acreage in Other Americas of 490 gross and 311 net thousands of acres for 2021 and 2020.

Separate acreage data for oil and gas are not maintained because, in many instances, both are produced from the same acreage.

C. Gross and Net Undeveloped Acreage

	Year-End 2021		Year-End 2020	
	Gross	Net	Gross	Net
		(thousands of acres)		
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	6,751	2,807	6,969	2,967
Canada/ Other Americas *(1)*	36,764	18,246	37,833	18,985
Europe	14,458	5,961	14,802	6,018
Africa	23,797	15,186	35,956	24,558
Asia	766	227	888	280
Australia/ Oceania	8,638	4,112	12,971	6,265
Total Consolidated Subsidiaries	91,174	46,539	109,419	59,073
Equity Companies				
United States	159	64	160	64
Europe	596	139	765	214
Africa	596	149	596	149
Asia	—	—	—	—
Total Equity Companies	1,351	352	1,521	427
Total gross and net undeveloped acreage	92,525	46,891	110,940	59,500

(1) Includes undeveloped acreage in Other Americas of 26,084 gross and 12,471 net thousands of acres for 2021 and 2020.

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 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 2014. Pursuant to the amended law, the production term for an onshore unconventional concession is 35 years, and 25 years for a conventional concession, with unlimited 10-year extensions possible, once a field has been developed. In 2019, the government granted three offshore exploration licenses, with terms of eight years, divided into two exploration periods of four years, with an optional extension of five years for each license. Two onshore exploration concessions were initially granted prior to the amendment and are governed under Provincial Law with expiration terms through 2024.

Brazil

The exploration and production of oil and gas are governed by concession contracts and production sharing contracts. Concession contracts provide for an exploration period of up to 8 years and a production period of 27 years. Production sharing contracts provide for an exploration period of up to 7 years and a production period of up to 28 years.

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 and 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 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 subject to 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.

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 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.

AFRICA

Angola

Exploration and production activities are governed by either production sharing agreements or other contracts with initial exploration terms ranging from three to four years with options to extend from one to five years. The production periods range from 20 to 30 years, and the agreements generally provide for negotiated extensions.

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 negotiated with the State Ministry of Mines and Hydrocarbons. The production period for crude oil is 30 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 an approved plan of development becomes effective 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, with blocks Z5-C and Z5-D having an initial exploration phase that expires in 2022 and block A5-B's initial exploration phase expiring in 2023 after being granted a one-year extension. 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 10-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 10-year exploration period, and OMLs have a 20-year production period that may be extended, subject to the partial relinquishment provision of the Petroleum Industry Act (PIA) enacted on August 16, 2021.

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.

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 once for a period of four years with a total contract period of 30 years including an exploitation period. PSC terms can be extended for a maximum of 20 years for each extension with the approval of the government.

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.

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 10-year extensions.

Malaysia

Production activities are governed by production sharing contracts (PSCs) negotiated with the national oil company. The PSCs have production terms of 25 years. Extensions are generally subject to the national oil company's prior written approval.

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. The initial terms for these rights generally extend for 25 years. Extensions and terms are subject to State of Qatar approval.

Russia

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

Thailand

The Petroleum Act of 1971 allows production under ExxonMobil's concessions for 30 years with a 10-year extension at terms generally prevalent at the time. In 2021, one concession was extended to 2031.

United Arab Emirates

An interest in the development and production activities of the offshore Upper Zakum 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 for further consecutive period(s) 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, provided that the total period of all extensions granted does not exceed 10 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 2021 *(1)*

		ExxonMobil Share KBD *(2)*	ExxonMobil Interest %
United States			
Joliet	Illinois	254	100
Baton Rouge	Louisiana	521	100
Billings	Montana	60	100
Baytown	Texas	561	100
Beaumont	Texas	369	100
Total United States		1,765	
Canada			
Strathcona	Alberta	196	69.6
Nanticoke	Ontario	113	69.6
Sarnia	Ontario	119	69.6
Total Canada		428	
Europe			
Antwerp	Belgium	307	100
Fos-sur-Mer	France	133	82.9
Gravenchon	France	244	82.9
Karlsruhe	Germany	78	25
Trecate	Italy	132	75.2
Rotterdam	Netherlands	192	100
Fawley	United Kingdom	262	100
Total Europe		1,348	
Asia Pacific			
Fujian	China	67	25
Jurong/PAC	Singapore	592	100
Sriracha	Thailand	167	66
Total Asia Pacific		826	
Middle East			
Yanbu	Saudi Arabia	200	50
Total Worldwide		4,567	

(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 2021

United States	
Owned/leased	—
Distributors/resellers	11,315
Total United States	11,315
Canada	
Owned/leased	—
Distributors/resellers	2,389
Total Canada	2,389
Europe	
Owned/leased	197
Distributors/resellers	5,834
Total Europe	6,031
Asia Pacific	
Owned/leased	566
Distributors/resellers	1,327
Total Asia Pacific	1,893
Latin America	
Owned/leased	—
Distributors/resellers	489
Total Latin America	489
Middle East/Africa	
Owned/leased	223
Distributors/resellers	205
Total Middle East/Africa	428
Worldwide	
Owned/leased	986
Distributors/resellers	21,559
Total Worldwide	22,545

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 2021 *(1)*

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest %
		(millions of metric tons per year)				
North America						
Baton Rouge	Louisiana	1.1	1.3	0.5	—	100
Baytown	Texas	4.0	—	0.7	0.6	100
Beaumont	Texas	0.9	1.7	—	0.3	100
Corpus Christi	Texas	0.9	0.7	—	—	50
Mont Belvieu	Texas	—	2.3	—	—	100
Sarnia	Ontario	0.3	0.5	—	—	69.6
Total North America		7.2	6.5	1.2	0.9	
Europe						
Antwerp	Belgium	—	0.4	—	—	100
Fife	United Kingdom	0.4	—	—	—	50
Gravenchon	France	0.4	0.4	0.3	—	100
Meerhout	Belgium	—	0.5	—	—	100
Rotterdam	Netherlands	—	—	—	0.7	100
Total Europe		0.8	1.3	0.3	0.7	
Middle East						
Al Jubail	Saudi Arabia	0.7	0.7	—	—	50
Yanbu	Saudi Arabia	1.0	0.7	0.2	—	50
Total Middle East		1.7	1.4	0.2	—	
Asia Pacific						
Fujian	China	0.3	0.2	0.2	0.2	25
Singapore	Singapore	1.9	1.9	0.9	1.8	100
Sriracha	Thailand	—	—	—	0.5	66
Total Asia Pacific		2.2	2.1	1.1	2.5	
Total Worldwide		11.9	11.2	2.8	4.1	

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

Due to rounding, numbers presented above may not add up precisely to the totals indicated.

ITEM 3. LEGAL PROCEEDINGS

ExxonMobil has elected to use a $1 million threshold for disclosing environmental proceedings.

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.

Information about our Executive Officers
(positions and ages as of February 23, 2022)

Darren W. Woods	*Chairman of the Board*	
Held current title since:	January 1, 2017	Age: 57

Mr. Darren W. Woods became a Director and President of Exxon Mobil Corporation on January 1, 2016, and Chairman of the Board and Chief Executive Officer of Exxon Mobil Corporation on January 1, 2017, positions he continues to hold as of this filing date.

Neil A. Chapman	*Senior Vice President*	
Held current title since:	January 1, 2018	Age: 59

Mr. Neil A. Chapman 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.

Kathryn A. Mikells	*Senior Vice President and Chief Financial Officer*	
Held current title since:	August 9, 2021	Age: 56

Ms. Kathryn A. Mikells was Chief Financial Officer and a member of the board of directors of Diageo plc November 2015 – June 2021. Prior to that time, she held Chief Financial Officer positions at Xerox, ADT, Nalco, and United Airlines, where she also served as Vice President of Investor Relations and Treasurer. She became Senior Vice President and Chief Financial Officer of Exxon Mobil Corporation on August 9, 2021, positions she continues to hold as of this filing date.

Jack P. Williams, Jr.	*Senior Vice President*	
Held current title since:	June 1, 2014	Age: 58

Mr. Jack P. Williams, Jr. became Senior Vice President of Exxon Mobil Corporation on June 1, 2014, a position he continues to hold as of this filing date.

Ian S. Carr	*Vice President*	
Held current title since:	September 1, 2020	Age: 58

Mr. Ian S. Carr was Vice President, Strategy and Planning, ExxonMobil Refining & Supply Company May 1, 2014 – July 31, 2017. He was Vice President, Upstream Strategy and Planning, ExxonMobil Gas & Power Marketing Company August 1, 2017 – March 31, 2019. He was Vice President, Strategy and Portfolio Management, ExxonMobil Upstream Business Development Company April 1, 2019 – September 30, 2019. He was Senior Vice President, Fuels, ExxonMobil Fuels & Lubricants Company October 1, 2019 – August 31, 2020. He became President of ExxonMobil Fuels & Lubricants Company and Vice President of Exxon Mobil Corporation on September 1, 2020, positions he continues to hold as of this filing date.

Linda D. DuCharme	*Vice President* *President, ExxonMobil Integrated Solutions Company*	
Held current title since:	July 1, 2020, and April 1, 2019, respectively	Age: 57

Ms. Linda D. DuCharme was President of ExxonMobil Global Services Company August 1, 2016 – March 31, 2019. She became President of ExxonMobil Upstream Integrated Solutions Company April 1, 2019, and President of ExxonMobil Upstream Business Development Company and Vice President of Exxon Mobil Corporation on July 1, 2020, positions she continues to hold as of this filing date.

Len M. Fox	*Vice President and Controller*	

Jon M. Gibbs	*President, ExxonMobil Global Projects Company*	
Held current title since:	April 1, 2021	Age: 50

Mr. Jon M. Gibbs was Vice President, Asia Pacific and Middle East, ExxonMobil Development Company January 1, 2016 – January 14, 2019. He was Upstream Organization Design Team Lead, ExxonMobil Development Company January 15, 2019 – March 31, 2019. He was President, ExxonMobil Global Services Company April 1, 2019 – June 30, 2020. He was Senior Vice President, Global Project Delivery, ExxonMobil Global Projects Company July 1, 2020 – March 31, 2021. He became President of ExxonMobil Global Projects Company on April 1, 2021, a position he continues to hold as of this filing date.

Stephen A. Littleton	*Vice President – Investor Relations and Secretary*	
Held current title since:	March 15, 2020	Age: 56

Mr. Stephen A. Littleton was Assistant Controller of Exxon Mobil Corporation June 1, 2015 – April 30, 2018. He was Vice President, Downstream Business Services and Downstream Controller May 1, 2018 – March 14, 2020. He became Vice President – Investor Relations and Secretary of Exxon Mobil Corporation on March 15, 2020, positions he continues to hold as of this filing date.

Liam M. Mallon	*Vice President*	
Held current title since:	April 1, 2019	Age: 59

Mr. Liam M. Mallon was President of ExxonMobil Development Company January 1, 2017 – March 31, 2019. He became President of ExxonMobil Upstream Oil & Gas Company and Vice President of Exxon Mobil Corporation on April 1, 2019, positions he continues to hold as of this filing date.

Karen T. McKee	*Vice President*	
Held current title since:	April 1, 2019	Age: 55

Ms. Karen T. McKee was Vice President, Basic Chemicals, ExxonMobil Chemical Company May 1, 2014 – July 31, 2017. She was Senior Vice President, Basic Chemicals, Integration & Growth, ExxonMobil Chemical Company August 1, 2017 – March 31, 2019. She became President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation on April 1, 2019, positions she continues to hold as of this filing date.

Craig S. Morford	*Vice President and General Counsel*	
Held current title since:	November 1, 2020	Age: 63

Mr. Craig S. Morford was Chief Legal and Compliance Officer of Cardinal Heath, Inc. prior to joining Exxon Mobil Corporation in May 2019. He was Deputy General Counsel of Exxon Mobil Corporation May 1, 2019 – October 31, 2020. He became Vice President and General Counsel of Exxon Mobil Corporation on November 1, 2020, positions he continues to hold as of this filing date.

James M. Spellings, Jr.	*Vice President, Treasurer and General Tax Counsel*	
Held current title since:	March 1, 2010 (Vice President and General Tax Counsel) April 1, 2020 (Treasurer)	Age: 60

Mr. James M. Spellings, Jr. became Vice President and General Tax Counsel of Exxon Mobil Corporation on March 1, 2010, and Treasurer of Exxon Mobil Corporation on April 1, 2020, positions he continues to hold as of this filing date.

Theodore J. Wojnar, Jr.	*Vice President – Corporate Strategic Planning*	

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. The above-named officers are required to file reports under Section 16 of the Securities Exchange Act of 1934.

PART II

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

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 327,689 registered shareholders of ExxonMobil common stock at December 31, 2021. At January 31, 2022, the registered shareholders of ExxonMobil common stock numbered 325,508.

On January 26, 2022, the Corporation declared an $0.88 dividend per common share, payable March 10, 2022.

Reference is made to Item 12 in Part III of this report.

Issuer Purchases of Equity Securities for Quarter Ended December 31, 2021

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 2021	-		-	
November 2021	-		-	
December 2021	-		-	
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 - In January 2022, the Corporation initiated a share repurchase program of up to $10 billion over 12 to 24 months.

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” 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 *(PCAOB ID 238)* dated February 23, 2022, beginning with the section entitled "Report of Independent Registered Public Accounting Firm" and continuing through "Note 19: Income and Other Taxes";
- "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, Chief Financial Officer, and Principal Accounting Officer have evaluated the Corporation's disclosure controls and procedures as of December 31, 2021. 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, Chief 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, 2021.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2021, 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.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Reference is made to the section of this report titled “Information about our Executive Officers”.

Incorporated by reference to the following from the registrant’s definitive proxy statement for the 2022 annual meeting of shareholders (the “2022 Proxy Statement”):

- The section entitled “Election of Directors”;
- The portions entitled “Director Qualifications”, “Director Nomination Process and Board Succession”, and “Code of Ethics and Business Conduct” of the section entitled “Corporate Governance”; and
- The “Audit Committee” portion, “Director Independence” portion, “Board Meetings and Annual Meeting Attendance” portion, and the membership table of the portion entitled “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 2022 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 2022 Proxy Statement.

Equity Compensation Plan Information

Plan Category	*(a)* Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	*(b)* Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	*(c)* Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	42,039,960 *(1)*	—	66,104,769 *(2)(3)*
Equity compensation plans not approved by security holders	—	—	—
Total	42,039,960	—	66,104,769

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

(2) Available shares can be granted in the form of restricted stock or other stock-based awards. Includes 65,754,069 shares available for award under the 2003 Incentive Program and 350,700 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 portion entitled “Related Person Transactions and Procedures” of the section entitled “Director and Executive Officer Stock Ownership”; and the portion entitled “Director Independence” of the section entitled “Corporate Governance” of the registrant’s 2022 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 2022 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.

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

ITEM 16. FORM 10-K SUMMARY

None.

FINANCIAL SECTION

TABLE OF CONTENTS

BUSINESS PROFILE

Financial	Earnings (Loss) After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
	2021	2020	2021	2020	2021	2020	2021	2020
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	3,663	(19,385)	55,305	65,780	6.6	(29.5)	4,018	6,817
Non-U.S.	12,112	(645)	101,645	107,506	11.9	(0.6)	8,236	7,614
Total	15,775	(20,030)	156,950	173,286	10.1	(11.6)	12,254	14,431
Downstream								
United States	1,314	(852)	12,292	11,472	10.7	(7.4)	1,000	2,344
Non-U.S.	791	(225)	18,929	18,682	4.2	(1.2)	1,095	1,877
Total	2,105	(1,077)	31,221	30,154	6.7	(3.6)	2,095	4,221
Chemical								
United States	4,502	1,277	15,714	14,436	28.6	8.8	1,367	2,002
Non-U.S.	3,294	686	17,281	17,600	19.1	3.9	876	714
Total	7,796	1,963	32,995	32,036	23.6	6.1	2,243	2,716
Corporate and Financing	(2,636)	(3,296)	1,724	(1,445)	—	—	3	6
Total	23,040	(22,440)	222,890	234,031	10.9	(9.3)	16,595	21,374

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

Operating	2021	2020		2021	2020
	(thousands of barrels daily)			*(thousands of barrels daily)*	
Net liquids production			Refinery throughput		
United States	721	685	United States	1,623	1,549
Non-U.S.	1,568	1,664	Non-U.S.	2,322	2,224
Total	2,289	2,349	Total	3,945	3,773
	(millions of cubic feet daily)			*(thousands of barrels daily)*	
Natural gas production available for sale			Petroleum product sales *(2)*		
United States	2,746	2,691	United States	2,257	2,154
Non-U.S.	5,791	5,780	Non-U.S.	2,905	2,741
Total	8,537	8,471	Total	5,162	4,895
	(thousands of oil-equivalent barrels daily)			*(thousands of metric tons)*	
Oil-equivalent production *(1)*	3,712	3,761	Chemical prime product sales *(2) (3)*		
			United States	9,724	9,010
			Non-U.S.	16,608	16,439
			Total	26,332	25,449

(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

	2021	2020	2019
	(millions of dollars, except where stated otherwise)		
Sales and other operating revenue	276,692	178,574	255,583
Earnings (loss)			
Upstream	15,775	(20,030)	14,442
Downstream	2,105	(1,077)	2,323
Chemical	7,796	1,963	592
Corporate and Financing	(2,636)	(3,296)	(3,017)
Net income (loss) attributable to ExxonMobil	23,040	(22,440)	14,340
Earnings (loss) per common share (dollars)	5.39	(5.25)	3.36
Earnings (loss) per common share – assuming dilution (dollars)	5.39	(5.25)	3.36
Earnings (loss) to average ExxonMobil share of equity (percent)	14.1	(12.9)	7.5
Working capital	2,511	(11,470)	(13,937)
Ratio of current assets to current liabilities (times)	1.04	0.80	0.78
Additions to property, plant and equipment	12,541	17,342	24,904
Property, plant and equipment, less allowances	216,552	227,553	253,018
Total assets	338,923	332,750	362,597
Exploration expenses, including dry holes	1,054	1,285	1,269
Research and development costs	843	1,016	1,214
Long-term debt	43,428	47,182	26,342
Total debt	47,704	67,640	46,920
Debt to capital (percent)	21.4	29.2	19.1
Net debt to capital (percent) *(1)*	18.9	27.8	18.1
ExxonMobil share of equity at year-end	168,577	157,150	191,650
ExxonMobil share of equity per common share (dollars)	39.77	37.12	45.26
Weighted average number of common shares outstanding (millions)	4,275	4,271	4,270
Number of regular employees at year-end (thousands) *(2)*	63.0	72.0	74.9

(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.

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 both from 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 assets are contributing to the Corporation's strategic objectives. Assets are divested when they are no longer meeting these objectives or are worth considerably more to others. Because of the regular nature of this activity, we believe it is useful for investors to consider proceeds associated with asset sales together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

Cash Flow From Operations and Asset Sales	**2021**	**2020**	**2019**
		(millions of dollars)	
Net cash provided by operating activities	48,129	14,668	29,716
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	3,176	999	3,692
Cash flow from operations and asset sales	51,305	15,667	33,408

Capital Employed

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

Capital Employed	2021	2020	2019
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	338,923	332,750	362,597
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(52,367)	(35,905)	(43,411)
Total long-term liabilities excluding long-term debt	(63,169)	(65,075)	(73,328)
Noncontrolling interests share of assets and liabilities	(8,746)	(8,773)	(8,839)
Add ExxonMobil share of debt-financed equity company net assets	4,001	4,140	3,906
Total capital employed	218,642	227,137	240,925
Total corporate sources: debt and equity perspective			
Notes and loans payable	4,276	20,458	20,578
Long-term debt	43,428	47,182	26,342
ExxonMobil share of equity	168,577	157,150	191,650
Less noncontrolling interests share of total debt	(1,640)	(1,793)	(1,551)
Add ExxonMobil share of equity company debt	4,001	4,140	3,906
Total capital employed	218,642	227,137	240,925

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 one of the best measures of historical capital productivity in our capital-intensive, long-term industry. Additional measures, which are more cash flow based, are used to make investment decisions.

Return on Average Capital Employed	**2021**	**2020**	**2019**
		(millions of dollars)	
Net income (loss) attributable to ExxonMobil	23,040	(22,440)	14,340
Financing costs (after-tax)			
Gross third-party debt	(1,196)	(1,272)	(1,075)
ExxonMobil share of equity companies	(170)	(182)	(207)
All other financing costs – net	11	666	141
Total financing costs	(1,355)	(788)	(1,141)
Earnings (loss) excluding financing costs	24,395	(21,652)	15,481
Average capital employed	222,890	234,031	236,603
Return on average capital employed – corporate total	10.9%	(9.3)%	6.5%

Structural Cost Savings

Structural cost savings describe decreases in the below expenses as a result of operational efficiencies, workforce reductions and other cost saving measures that are expected to be sustainable compared to 2019 levels. Relative to 2019, estimated cumulative annual structural cost savings totaled $4.9 billion, of which $1.9 billion was achieved in 2021. The total change between periods in expenses below will reflect both structural cost savings and other changes in spend, including market factors, such as energy costs, inflation, and foreign exchange impacts, as well as changes in activity levels and costs associated with new operations. Structural cost savings are stewarded internally to support management's oversight of spending over time. This measure is useful for investors to understand the Corporation's efforts to optimize spending through disciplined expense management.

Consolidated Statement of Income Line Items Targeted for Structural Cost Savings	**2021**	**2020**	**2019**
		(millions of dollars)	
Production and manufacturing expenses	36,035	30,431	36,826
Selling, general and administrative expenses	9,574	10,168	11,398
Exploration expenses, including dry holes	1,054	1,285	1,269
Total	46,663	41,884	49,493

FREQUENTLY USED TERMS

Earnings (Loss) excluding Identified Items

Earnings (loss) excluding Identified Items, are earnings (loss) excluding individually significant non-operational events with an absolute corporate total earnings impact of at least $250 million in a given quarter. The earnings (loss) impact of an Identified Item for an individual segment in a given quarter may be less than $250 million when the item impacts several segments or several periods. Management uses these figures to improve comparability of the underlying business across multiple periods by isolating and removing significant non-operational events from business results. The Corporation believes this view provides investors increased transparency into business results and trends, and provides investors with a view of the business as seen through the eyes of management. Earnings (loss) excluding Identified Items is not meant to be viewed in isolation or as a substitute for net income (loss) attributable to ExxonMobil as prepared in accordance with U.S. GAAP.

	2021			2020			2019		
Upstream	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
					(millions of dollars)				
Earnings (loss) (U.S. GAAP)	3,663	12,112	15,775	(19,385)	(645)	(20,030)	536	13,906	14,442
Impairments	(263)	(489)	(752)	(17,092)	(2,244)	(19,336)	—	—	—
Gain/(loss) on sale of assets	—	459	459	—	—	—	—	3,679	3,679
Inventory valuation - lower of cost or market	—	—	—	—	(61)	(61)	—	—	—
Tax-related items	—	—	—	—	(297)	(297)	—	755	755
Contractual provisions	—	(250)	(250)	—	—	—	—	—	—
Identified Items	(263)	(280)	(543)	(17,092)	(2,602)	(19,694)	—	4,434	4,434
Earnings (loss) excluding Identified Items	3,926	12,392	16,318	(2,293)	1,957	(336)	536	9,472	10,008

	2021			2020			2019		
Downstream	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
					(millions of dollars)				
Earnings (loss) (U.S. GAAP)	1,314	791	2,105	(852)	(225)	(1,077)	1,717	606	2,323
Impairments	—	—	—	(4)	(593)	(597)	—	—	—
Gain/(loss) on sale of assets	4	—	4	—	—	—	—	—	—
Tax-related items	—	—	—	—	(262)	(262)	—	(9)	(9)
Identified Items	4	—	4	(4)	(855)	(859)	—	(9)	(9)
Earnings (loss) excluding Identified Items	1,310	791	2,101	(848)	630	(218)	1,717	615	2,332

Chemical	2021 U.S.	2021 Non-U.S.	2021 Total	2020 U.S.	2020 Non-U.S.	2020 Total	2019 U.S.	2019 Non-U.S.	2019 Total
				(millions of dollars)					
Earnings (loss) (U.S. GAAP)	4,502	3,294	7,796	1,277	686	1,963	206	386	592
Impairments	—	—	—	(90)	(2)	(92)	—	—	—
Gain/(loss) on sale of assets	494	136	630	—	—	—	—	—	—
Tax-related items	—	—	—	—	(22)	(22)	—	2	2
Identified Items	494	136	630	(90)	(24)	(114)	—	2	2
Earnings (loss) excluding Identified Items	4,008	3,158	7,166	1,367	710	2,077	206	384	590

FREQUENTLY USED TERMS

Corporate and Financing	**2021**	**2020**	**2019**
		(millions of dollars)	
Earnings (loss) (U.S. GAAP)	(2,636)	(3,296)	(3,017)
Impairments	—	(35)	—
Gain/(loss) on sale of assets	(12)	—	(24)
Tax-related items	—	—	332
Severance charges	(52)	(326)	—
Identified Items	(64)	(361)	308
Earnings (loss) excluding Identified Items	(2,572)	(2,935)	(3,325)

Corporate Total	**2021**	**2020**	**2019**
		(millions of dollars)	
Net income (loss) attributable to ExxonMobil (U.S. GAAP)	23,040	(22,440)	14,340
Impairments	(752)	(20,060)	—
Gain/(loss) on sale of assets	1,081	—	3,655
Inventory valuation - lower of cost or market	—	(61)	—
Tax-related items	—	(581)	1,080
Severance charges	(52)	(326)	—
Contractual provisions	(250)	—	—
Identified Items	27	(21,028)	4,735
Earnings (loss) excluding Identified Items	23,013	(1,412)	9,605

References in Frequently Used Terms and Management's Discussion & Analysis to total corporate earnings (loss) mean net income (loss) attributable to ExxonMobil from the Consolidated Statement of Income. Unless otherwise indicated, references to earnings (loss), Upstream, Downstream, Chemical and Corporate and Financing earnings (loss), and earnings (loss) per share are ExxonMobil’s share after excluding amounts attributable to noncontrolling interests.

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

FORWARD-LOOKING STATEMENTS

Outlooks, projections, goals, targets, descriptions of strategic plans and objectives, and other statements of future events or conditions in this release are forward-looking statements. Similarly, emission-reduction roadmaps are dependent on future market factors, such as continued technological progress and policy support, and also represent forward-looking statements. Actual future results, including future energy demand and mix; financial and operating performance; realized price and margins; dividends and shareholder returns, including the timing and amounts of share repurchases; volume growth; project plans, timing, costs, and capacities; capital expenditures, including lower-emissions and environmental expenditures; cost reductions and structural cost savings; integration benefits; emission intensity and absolute emissions reductions; achievement of ambitions to reach Scope 1 and Scope 2 net-zero from operated assets by 2050, to reduce methane emissions and flaring, or to complete major asset emission reduction roadmaps; implementation and outcomes of carbon capture and storage projects and infrastructure, renewable fuel projects, blue hydrogen projects, and other technology efforts; the impact of new technologies on society and industry; capital expenditures and mix; investment returns; accounting and financial reporting effects resulting from market or regulatory developments and ExxonMobil's responsive actions, including potential impairment charges; and the outcome of litigation and tax contingencies, could differ materially due to a number of factors. These include global or regional changes in the supply and demand for oil, natural gas, petrochemicals, and feedstocks and other market or economic conditions that impact demand, prices and differentials; policy and consumer support for lower-emission products and technologies in different jurisdictions; the impact of company actions to protect the health and safety of employees, vendors, customers, and communities; actions of competitors and commercial counterparties; the ability to access short- and long-term debt markets on a timely and affordable basis; the severity, length and ultimate impact of COVID-19 variants and government responses on people and economies; reservoir performance; the outcome of exploration projects and timely completion of development and construction projects; regulatory actions targeting public companies in the oil and gas industry; changes in local, national, or international law, taxes, regulation or policies affecting our business, including environmental regulations and timely granting of governmental permits; war, trade agreements and patterns, shipping blockades or harassment, and other political or security disturbances; the pace of regional and global economic recovery from the pandemic and the occurrence and severity of future outbreaks; opportunities for and regulatory approval of potential investments or divestments; the actions of competitors; the capture of efficiencies within and between business lines and the ability to maintain near-term cost reductions as ongoing efficiencies while maintaining future competitive positioning; unforeseen technical or operating difficulties; the development and competitiveness of alternative energy and emission reduction technologies; the results of research programs; the ability to bring new technologies to commercial scale on a cost-competitive basis; general economic conditions including the occurrence and duration of economic recessions; and other factors discussed under Item 1A. Risk Factors.

Energy demand models are forward-looking by nature and aim to replicate system dynamics of the global energy system, requiring simplifications. The reference to any scenario in this report, including any potential net-zero scenarios, does not imply ExxonMobil views any particular scenario as likely to occur. In addition, energy demand scenarios require assumptions on a variety of parameters. As such, the outcome of any given scenario using an energy demand model comes with a high degree of uncertainty. For example, the IEA describes its NZE scenario as extremely challenging, requiring unprecedented innovation, unprecedented international cooperation and sustained support and participation from consumers. Third-party scenarios discussed in this report reflect the modeling assumptions and outputs of their respective authors, not ExxonMobil, and their use by ExxonMobil is not an endorsement by ExxonMobil of their underlying assumptions, likelihood or probability. Investment decisions are made on the basis of ExxonMobil's separate planning process, but may be secondarily tested for robustness or resiliency against different assumptions, including against various scenarios. Any use of the modeling of a third-party organization within this report does not constitute or imply an endorsement by ExxonMobil of any or all of the positions or activities of such organization.

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, manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen, and biofuels. ExxonMobil's operating segments are Upstream, Downstream, and Chemical. Where applicable ExxonMobil voluntarily discloses additional U.S., Non-U.S. and regional splits to help investors better understand the company's operations.

In January 2022, the Corporation announced that effective April 2022 it is streamlining its business structure by combining the Chemical and Downstream businesses. The company will be organized along three businesses – Upstream, Product Solutions, and Low Carbon Solutions, aligning along market-focused value chains. Product Solutions will consist of Energy Products, Specialty Products and Chemical Products. Low Carbon Solutions will continue to be included in Corporate and Financing. The businesses will be supported by a combined technology organization, and other centralized service-delivery groups, building on the establishment of a worldwide major projects organization in 2019.

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

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 and Low Carbon Solutions business, generally 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 operating and capital objectives in addition to providing the economic assumptions used for investment evaluation purposes. The foundation for the assumptions supporting the corporate plan is the Energy Outlook and corporate plan volume projections are based on individual field production profiles, which are also updated at least annually. Price ranges for crude oil, natural gas, including price differentials, refinery and chemical margins, volumes, development and operating costs, including greenhouse gas emission prices, and foreign currency exchange rates 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.

BUSINESS ENVIRONMENT

Long-Term Business Outlook

ExxonMobil's business planning is underpinned by a deep understanding of long-term energy fundamentals. These fundamentals include energy supply and demand trends, the scale and variety of energy needs worldwide; capability, practicality and affordability of energy alternatives including low-carbon solutions; greenhouse gas emission-reduction technologies; and supportive government policies. The company's Energy Outlook (Outlook) considers these fundamentals to form the basis for the company's long-term business planning, investment decisions, and research programs. The Outlook reflects the company's view of global energy demand and supply through 2050. It is a projection based on current trends in technology, government policies, consumer preferences, geopolitics, and economic development. In addition, ExxonMobil considers a range of scenarios - including remote scenarios - to help inform perspective of the future and enhance strategic thinking over time. Included in the range of these scenarios are the Intergovernmental Panel on Climate Change Lower 2°C and the International Energy Agency's Net Zero Emissions (IEA NZE) by 2050 scenario. To effectively evaluate the pace of change, ExxonMobil uses many scenarios to help identify signposts that provide leading indicators of future developments and allow for timely adjustments to the Outlook. The IEA describes the IEA NZE as extremely challenging, requiring all stakeholders – governments, businesses, investors and citizens – to take action this year and every year after so that the goal does not slip out of reach. The scenario assumes unprecedented and sustained energy efficiency gains, innovation and technology transfer, lower-emission investments, and globally coordinated greenhouse gas reduction policy. The IEA acknowledges that society is not on the IEA NZE pathway.

By 2050, the world's population is projected at around 9.7 billion people, or about 2 billion more than in 2019. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 2.5 percent per year, with economic output growing by around 125 percent by 2050 compared to 2019. 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 almost 15 percent from 2019 to 2050. 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 drives global energy demand higher, increasing use of energy-efficient technologies and practices as well as lower-emission products 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 2050, affecting energy requirements for power generation, transportation, industrial applications, and residential and commercial needs.

Under our Outlook, global electricity demand is expected to increase almost 75 percent from 2019 to 2050, with developing countries likely to account for about 80 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 expected to decline substantially and approach 15 percent of the world's electricity in 2050, versus nearly 35 percent in 2019, in part as a result of policies to improve air quality as well as reduce greenhouse gas emissions to address risks related to climate change. From 2019 to 2050, the amount of electricity supplied using natural gas, nuclear power, and renewables is expected to more than double, accounting for the entire growth in electricity supplies and offsetting the reduction of coal. Electricity from wind and solar is expected to increase more than 600 percent, helping total renewables (including other sources, e.g. hydropower) to account for about 80 percent of the increase in electricity supplies worldwide through 2050. Total renewables are expected to reach about 50 percent of global electricity supplies by 2050. Natural gas and nuclear are also expected to increase shares over the period to 2050, reaching more than 25 percent and about 10 percent of global electricity supplies, respectively, by 2050. 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 and policy developments.

Under our Outlook, energy for transportation - including cars, trucks, ships, trains and airplanes - is expected to increase by almost 25 percent from 2019 to 2050. Transportation energy demand is expected to account for over 40 percent of the growth in liquid fuels demand worldwide over this period. Light-duty vehicle demand for liquid fuels is projected to peak by around 2025 and then decline to levels seen in the early-2000s by 2050 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 2050, light-duty vehicles are expected to account for around 15 percent of global liquid fuels demand. During the same time period, nearly all the world's commercial transportation fleets are expected to continue to run on liquid fuels, including biofuels, 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 2050, global demand for liquid fuels is projected to grow to approximately 114 million barrels of oil equivalent per day, an increase of about 14 percent from 2019. The non-OECD share of global liquid fuels demand is expected to increase to nearly 70 percent by 2050, as liquid fuels demand in the OECD is expected to decline by more than 20 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 2050 as technology advances continue to expand the availability of economic and lower-carbon supply options. However, timely investments will remain critical to meeting global needs with reliable and affordable supplies.

Natural gas is a lower-emission, versatile and practical fuel for a wide variety of applications, and it is expected to grow the most of any primary energy type from 2019 to 2050, meeting about 55 percent of global energy demand growth. Global natural gas demand is expected to rise nearly 35 percent from 2019 to 2050, with more than half of that increase coming from 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 50 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 more than two-thirds of worldwide demand in 2050. Liquefied natural gas (LNG) trade will expand significantly, meeting about 40 percent of the increase in global demand growth, with much of this supply expected to help meet rising demand in Asia Pacific.

The world's energy mix is highly diverse and will remain so through 2050. Oil is expected to remain the largest source of energy with its share remaining close to 30 percent in 2050. Coal is currently the second largest source of energy, but it is expected to lose that position to natural gas in the next few years. The share of natural gas is expected to reach more than 25 percent by 2050, while the share of coal falls to about half that of natural gas. 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 expected to exceed 20 percent of global energy by 2050, with biomass, hydro and geothermal contributing a combined share of more than 10 percent. Total energy supplied from wind, solar and biofuels is expected to increase rapidly, growing over 420 percent from 2019 to 2050, when they are projected to be about 10 percent of the world energy mix.

To meet this projected demand under our Outlook, 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 2050 will be significant. This reflects a fundamental aspect of the oil and natural gas business as the International Energy Agency (IEA) describes in its World Energy Outlook 2021.

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 Energy Outlook. 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 Energy Outlook reflects an environment with increasingly stringent climate policies and is consistent with the global aggregation of Nationally Determined Contributions (NDCs), as available at the end of 2020, which were submitted by signatories to the United Nations Framework Convention on Climate Change (UNFCCC) 2015 Paris Agreement. Our Energy 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, and, as applicable, use of a proxy cost of carbon or assessment of targeted policies (e.g. automotive fuel economy standards). For purposes of the Energy Outlook, a proxy cost on energy-related CO2 emissions is assumed to reach about $100 per metric ton in 2050 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. The Corporation continues to monitor the updates to the NDCs that nations provided around COP 26 in Glasgow in November 2021 as well as other policy developments in light of net-zero ambitions recently formulated by some nations.

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

The information provided in the Outlook includes ExxonMobil’s internal estimates and projections based upon internal data and analyses as well as publicly available information from external sources including the International Energy Agency.

Leading the Drive to Net Zero

The company plans to play a leading role in the energy transition by leveraging its core capabilities to meet society’s needs for products essential for modern life, while addressing the challenge of climate change.

The Corporation announced its ambition to achieve net-zero emissions from its operated assets by 2050 (Scope 1 and 2 greenhouse gas emissions) and is taking a comprehensive approach centered on developing detailed emission-reduction roadmaps for major operated assets. The company’s roadmap approach identifies greenhouse gas emission-reduction opportunities and the investment and future policy needs required to achieve net-zero. The roadmaps are tailored to account for facility configuration and maintenance schedules, and they will be updated as technologies and policies evolve. Net-zero roadmaps for major assets, covering about 90% of the company’s greenhouse gas emissions, are scheduled to be completed by year-end 2022, and the remainder in 2023.

Our strategy uses our advantages in scale, integration, technology and people to build globally competitive businesses that lead industry in earnings and cash flow growth across a broad range of scenarios. The company’s plans to reduce greenhouse gas emissions through 2030 compared to 2016 levels support its net-zero ambition. The plans are expected to result in a 20-30% reduction in corporate-wide greenhouse gas intensity, including reductions of 40-50% in upstream intensity, 70-80% in methane intensity and 60-70% in flaring intensity. These plans include actions that are expected to reduce absolute corporate-wide greenhouse gas emissions by approximately 20%, including an estimated 70% reduction in methane emissions, 60% reduction in flaring emissions and 30% reduction in upstream emissions.

ExxonMobil established its Low Carbon Solutions business in early 2021, leveraging its unique combination of capabilities such as geophysics expertise and complex project management, to establish a new business in carbon capture and storage, hydrogen, and biofuels to accelerate emission reductions for customers and in its existing businesses.

The Corporation plans to invest in initiatives to lower greenhouse gas emissions. A significant focus is on scaling up carbon capture and storage, hydrogen, and biofuels. Stronger policy further accelerates development and deployment of lower-emission technologies, and would provide ExxonMobil additional investment opportunities to reduce greenhouse gas emissions. The company's robust research and development process, continued evaluation of emerging technologies, and global collaborations will be key to identifying and growing lower-emission opportunities. During the start-up phase, the Low Carbon Solutions business will be reflected in Corporate and Financing.

Recent Business Environment

In early 2020, the balance of supply and demand for petroleum and petrochemical products experienced two significant disruptive effects. On the demand side, the COVID-19 pandemic spread rapidly through most areas of the world resulting in substantial reductions in consumer and business activity and significantly reduced demand for crude oil, natural gas, and petroleum products. This reduction in demand coincided with announcements of increased production in certain key oil-producing countries which led to increases in inventory levels and sharp declines in prices for crude oil, natural gas, and petroleum products.

Demand for petroleum and petrochemical products has continued to recover through 2021, with the Corporation's financial results benefiting from stronger prices and margins, notably prices for crude oil and natural gas as well as Chemical product margins. The rate and pace of recovery, however, has varied across geographies and business lines, with Downstream margins only reaching the lower end of the 10-year range late in 2021 and jet demand continuing to lag. The Corporation continues to closely monitor industry and economic conditions amid this uneven global recovery from the COVID-19 pandemic which has brought unprecedented uncertainties to near-term economic outlooks.

The general rate of inflation across major countries of operation experienced a brief decline in the initial stage of the COVID-19 pandemic. However inflation rates increased in 2021 across major economies, with some regions experiencing multi-decade highs, largely reflecting overall imbalances between supply and demand recoveries from the pandemic. The underlying factors include, but are not limited to, global supply chain disruptions, shipping bottlenecks, labor market constraints, and side effects from monetary and fiscal expansions. The global economic recovery remains uneven, with uncertainties remaining. Prices for services and materials continue to evolve in response to fast-changing commodity markets, industry activities, as well as government policies, impacting operating and capital costs. The Corporation closely monitors market trends and works to mitigate cost impacts in all price environments through its economies of scale in global procurement, efficient project management practices, and general productivity improvements.

Organizational changes implemented over the past several years enabled the Corporation to realize nearly $5 billion of structural cost savings[1] versus 2019, leveraging increased operational efficiencies and reduced overhead costs. Included in these savings is the completion of the workforce reduction programs, announced in late 2020 and early 2021, which are estimated to generate savings of approximately $2 billion per year compared to 2019 from lower employee and contractor costs. The company continues to take actions to streamline its business structure to improve effectiveness and reduce costs. The changes more fully leverage global functional capabilities, improve line of sight to markets, and enhance resource allocation to the highest corporate priorities.

(1) Refer to Frequently Used Terms for definition of structural cost savings.

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

BUSINESS RESULTS

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 as well as a reduction in greenhouse gas emissions. 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, the proportion of oil-equivalent production from the Americas is generally expected to increase over the next several years. About half of the Corporation's global production comes from unconventional, deepwater and LNG resources. This proportion is generally expected to grow over the next few years.

The Upstream capital program continues to prioritize low cost-of-supply opportunities. In addition to continued development of Guyana, Brazil, and the Permian Basin, ExxonMobil has a strong pipeline of development projects. Most notable are our LNG developments in Mozambique, Papua New Guinea, and the Golden Pass LNG facility.

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; international trade patterns and relations; and other factors described in Item 1A. Risk Factors.

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, alternative energy sources, 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 tests the resiliency of its annual plans and major investments across a range of price scenarios.

Key Recent Events

Significant progress was made on key new developments in Guyana, Brazil, the Permian Basin, and Mozambique during 2021.

Guyana: Exploration success continued with additional discoveries increasing the estimated recoverable resource on the Stabroek block. The Liza Unity floating production, storage and offloading vessel arrived in Guyanese waters in late 2021 and started production in February 2022. In Payara, the third project, development drilling activities started in late 2021 and it remains on schedule for 2024 start-up. Yellowtail is the fourth and largest world-class development project and is expected to achieve first oil in 2025, following issuance of the production license.

Permian: Production volumes averaged about 460 thousand oil-equivalent barrels per day (koebd) in 2021, nearly 100 koebd year-on-year production increase which exceeded expectations. The Corporation was successful in increasing drilling performance and continuing to improve capital efficiency. In December, ExxonMobil announced plans to achieve net-zero greenhouse gas emissions (Scope 1 and 2) by 2030 from our unconventional operations in the Permian Basin.

Brazil: ExxonMobil announced its Final Investment Decision for the Bacalhau Phase 1 development in June 2021 with start-up planned for 2024.

Mozambique: The Area 4 Coral South Floating LNG (FLNG) development continues as planned, targeting start-up in 2022, making Mozambique an LNG exporter. The Coral Sul FLNG vessel began tow to field in November 2021.

Upstream Financial Results

	2021	2020	2019
		(millions of dollars)	
Earnings (loss) (U.S. GAAP)			
United States	3,663	(19,385)	536
Non-U.S.	12,112	(645)	13,906
Total	15,775	(20,030)	14,442
Identified Items *(1)*			
United States	(263)	(17,092)	—
Non-U.S.	(280)	(2,602)	4,434
Total	(543)	(19,694)	4,434
Earnings (loss) excluding Identified Items *(1)*			
United States	3,926	(2,293)	536
Non-U.S.	12,392	1,957	9,472
Total	16,318	(336)	10,008

2021 Upstream Earnings Factor Analysis
(millions of dollars)
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Price – Higher realizations increased earnings by $14,960 million.

Volume – Unfavorable volume and mix effects decreased earnings by $340 million.

Other – All other items increased earnings by $2,040 million, primarily driven by lower expenses of $1,360 million and one-time favorable tax items.

Identified Items *(1)* – 2020 $(19,694) million loss primarily impairments of dry gas assets; 2021 $(543) million loss as a result of impairments of $(752) million and contractual provisions of $(250) million, partly offset by a $459 million gain from the U.K. Central and Northern North Sea divestment.

(1) Refer to Frequently Used Terms for definition of Identified Items and earnings (loss) excluding Identified Items.

2020 Upstream Earnings Factor Analysis
(millions of dollars)
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Price – Lower realizations reduced earnings by $11,210 million.

Volume – Unfavorable volume and mix effects decreased earnings by $300 million.

Other – All other items increased earnings by $1,170 million, primarily driven by lower expenses of $960 million.

Identified Items *(1)* – 2019 $4,434 million gain primarily the $3,700 million gain from the Norway non-operated divestment; 2020 $(19,694) million loss primarily impairments of dry gas assets.

(1) Refer to Frequently Used Terms for definition of Identified Items and earnings (loss) excluding Identified Items.

Upstream Operational Results

	2021	2020	2019
Production of crude oil, natural gas liquids, bitumen and synthetic oil			
Net production	*(thousands of barrels daily)*		
United States	721	685	646
Canada/Other Americas	560	536	467
Europe	22	30	108
Africa	248	312	372
Asia	695	742	748
Australia/Oceania	43	44	45
Worldwide	2,289	2,349	2,386
Natural gas production available for sale			
Net production	*(millions of cubic feet daily)*		
United States	2,746	2,691	2,778
Canada/Other Americas	195	277	258
Europe	808	789	1,457
Africa	43	9	7
Asia	3,465	3,486	3,575
Australia/Oceania	1,280	1,219	1,319
Worldwide	8,537	8,471	9,394
	(thousands of oil-equivalent barrels daily)		
Oil-equivalent production *(2)*	3,712	3,761	3,952

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

2021

Liquids production – 2.3 million barrels per day decreased 60 thousand barrels per day reflecting higher demand and growth, more than offset by entitlements, decline, and divestments.

Natural gas production available for sale – 8.5 billion cubic feet per day increased 66 million cubic feet per day from 2020, reflecting higher demand, partly offset by divestments and Groningen production limit.

2020

Liquids production – 2.3 million barrels per day decreased 37 thousand barrels per day reflecting the impacts of government mandates, divestments, and lower demand, partly offset by growth and lower downtime.

Natural gas production available for sale – 8.5 billion cubic feet per day decreased 923 million cubic feet per day from 2019, reflecting divestments, lower demand, and higher downtime, partly offset by growth.

Upstream Additional Information

	2021	2020
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production) *(1)*		
Prior Year	3,761	3,952
Entitlements - Net Interest	(1)	(9)
Entitlements - Price / Spend / Other	(97)	67
Government Mandates	8	(110)
Divestments	(24)	(151)
Demand / Growth / Other	65	12
Current Year	3,712	3,761

(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.

Government Mandates are changes to ExxonMobil's sustainable production levels due to temporary non-operational production limits imposed by governments, generally upon a sector, type or method of production.

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.

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

Downstream

ExxonMobil's Downstream continues to be one of the largest, most integrated businesses among international oil companies (IOC), with significant positions across the full value chain including logistics, trading, refining, and marketing. The Corporation has a well-established presence in the Americas, Europe, and Asia Pacific.

Downstream strategies competitively position the business across a range of market conditions. These strategies focus on providing high-value and lower-emission products that customers need to power global mobility; leveraging strong operations performance; capitalizing on integration across all ExxonMobil businesses; maximizing value from advantaged technology and a robust pipeline of lower-emission opportunities; and improving portfolio competitiveness and resilience with advantaged investments and divestments.

With its large manufacturing footprint, ExxonMobil's Downstream earnings are closely tied to industry refining margins. Refining margins improved steadily throughout 2021, recovering from historic lows in 2020 driven by COVID-19 pandemic demand impacts. By the end of 2021, refining margins had recovered to the bottom of the 10-year historical band from 2010 to 2019. Demand for gasoline and diesel had essentially recovered to normal levels by the end of 2021, while jet fuel demand remained below historical levels reflecting continued COVID-19 restrictions. Refining margins are anticipated to further improve in the near term as the recovery in international travel increases demand for jet fuel, and strong chemical demand persists for products essential to modern life. With improving market conditions, we restarted projects in Beaumont, Texas and Singapore to further strengthen the portfolio by increasing production of high-value fuels and lubricants.

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 and the market prices for the range of products produced. 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 outlook is that industry refining margins will remain volatile subject to shifting consumer demand as well as capacity changes from refinery additions and closures. ExxonMobil's significant integration both within the Downstream value chains including lubricants, logistics, trading, refining, and marketing, as well as with Upstream and Chemical, improves our ability to generate shareholder value in a variety of market conditions.

ExxonMobil continues to grow fuels product sales in new markets near major production assets with continued progress in the Mexico and Indonesia markets. Similarly, the lubricants business continues to grow, especially in Asia Pacific and the industrial sector, leveraging world class brands and integration with basestocks refining capability. Through the Mobil brands, such as Mobil 1, ExxonMobil is the worldwide leader in synthetic motor oils.

The Downstream business is characterized by periods of margin volatility resulting from short-term and long-term supply and demand fluctuations. Proposed carbon policy and other climate-related regulations in many countries have the potential to increase industry volatility, both favorably and unfavorably. ExxonMobil continually evaluates the Downstream portfolio during all phases of the business cycle, which has resulted in numerous asset divestments and terminal conversions over the past decade to strengthen overall profitability and resiliency. When investing in the Downstream, ExxonMobil remains focused on projects resilient across a broad range of market conditions to support capturing value when opportunities emerge.

Key Recent Events

Lower-emission fuels: ExxonMobil announced plans for more than 40 thousand barrels per day of lower-emission fuels by 2025, including a new renewable diesel unit at the Strathcona refinery, and purchase agreements with Global Clean Energy in the U.S. and Biojet AS in Norway.

Terminal conversions: ExxonMobil converted the Slagen, Norway and Altona, Australia refineries into product import terminals capable of serving existing markets. Additionally, Refining New Zealand announced conversion of its refinery (in which ExxonMobil owns a 17% minority share) to a product import terminal in 2022.

Downstream Financial Results

	2021	2020	2019
		(millions of dollars)	
Earnings (loss) (U.S. GAAP)			
United States	1,314	(852)	1,717
Non-U.S.	791	(225)	606
Total	2,105	(1,077)	2,323
Identified Items *(1)*			
United States	4	(4)	—
Non-U.S.	—	(855)	(9)
Total	4	(859)	(9)
Earnings (loss) excluding Identified Items *(1)*			
United States	1,310	(848)	1,717
Non-U.S.	791	630	615
Total	2,101	(218)	2,332

2021 Downstream Earnings Factor Analysis
(millions of dollars)
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Margins – Increased earnings by $1,920 million as industry refining conditions improved.

Volume – Increased earnings by $100 million reflecting demand recovery and favorable mix.

Other – Increased earnings by $300 million due to lower expenses of $560 million, partly offset by unfavorable foreign exchange and LIFO impacts.

Identified Items *(1)* – 2020 $(859) million loss primarily as a result of impairments and unfavorable tax items.

(1) Refer to Frequently Used Terms for definition of Identified Items and earnings (loss) excluding Identified Items.

2020 Downstream Earnings Factor Analysis

(millions of dollars)

xom-20211231_g4.jpg

Margins – Decreased earnings by $3,820 million including the impact of weaker industry refining conditions.

Volume – Increased earnings by $370 million as manufacturing/yield improvement impacts were partly offset by weaker demand.

Other – Increased earnings by $900 million due to lower expenses of $1,290 million, partly offset by unfavorable LIFO inventory impacts of $410 million.

Identified Items *(1)* – 2020 $(859) million loss primarily as a result of impairments and unfavorable tax items.

(1) Refer to Frequently Used Terms for definition of Identified Items and earnings (loss) excluding Identified Items.

Downstream Operational Results

	2021	2020	2019
Refinery throughput	*(thousands of barrels daily)*		
United States	1,623	1,549	1,532
Canada	379	340	353
Europe	1,210	1,173	1,317
Asia Pacific	571	553	598
Other	162	158	181
Worldwide	3,945	3,773	3,981
Petroleum product sales *(2)*			
United States	2,257	2,154	2,292
Canada	448	418	476
Europe	1,340	1,253	1,479
Asia Pacific	653	651	738
Other	464	419	467
Worldwide	5,162	4,895	5,452
Gasoline, naphthas	2,158	1,994	2,220
Heating oils, kerosene, diesel oils	1,749	1,751	1,867
Aviation fuels	220	213	406
Heavy fuels	269	249	270
Specialty petroleum products	766	688	689
Worldwide	5,162	4,895	5,452

(2) Data reported net of purchases/sales contracts with the same counterparty.

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

Chemical

ExxonMobil is a leading global manufacturer and marketer of petrochemicals that support modern living. ExxonMobil helps meet society's evolving needs by providing a wide range of innovative, valuable product solutions in an efficient and responsible manner. This is enabled by ExxonMobil's proprietary technology combined with industry-leading scale and integration. These competitive advantages are underpinned by operational excellence, advantaged investments, and cost discipline.

In 2021, while many markets continued to be negatively impacted by COVID-19, demand for chemical products remained resilient in several key segments including food packaging, hygiene and medical. Overall chemical industry margins improved compared to 2020 due to continued strong packaging demand and industry supply disruptions. We were uniquely positioned to capture value from the market in 2021 due to our integration, enabling nimble feed and product optimization, and our advantaged global supply and logistics. These, along with our outstanding reliability performance and continued structural cost savings, delivered record annual earnings.

Worldwide demand for chemicals is expected to grow faster than the economy as a whole, driven by global population growth, an expanding middle class, and improving living standards. ExxonMobil's integration with refining, together with our high-value performance products and unique project execution capability, enhances our ability to generate returns on investments across a range of market environments. In 2021, ExxonMobil completed construction of our joint venture ethane cracker and associated derivative units near Corpus Christi, Texas. The project started up in late 2021 below budget and ahead of schedule. With improving market conditions, we also restarted other U.S. Gulf Coast growth projects, including projects in Baytown, Texas and Baton Rouge, Louisiana that will support the growing demand for high-value chemicals products.

Key Recent Events

China investment: ExxonMobil reached final investment decision to proceed with a multi-billion dollar chemical complex in the Dayawan Petrochemical Industrial Park in Huizhou, Guangdong Province in China. The facility will help meet expected demand growth for performance chemical products in China.

Advanced recycling: The Corporation is progressing construction of one of North America's largest plastic waste advanced recycling facilities in Baytown, Texas, which is expected to start operations in 2022. In addition, plans are underway for up to 500,000 metric tons annually of advanced recycling capacity to be added across multiple sites by 2026. These investments enabled commercial volumes of certified circular polymers to be made available to the market in 2021.

Materia acquisition: ExxonMobil acquired Materia, Inc., a technology company that has pioneered the development of a Nobel prize-winning technology for manufacturing a new class of materials. The innovative materials can be used in a number of applications, including wind turbine blades, electric vehicle parts, sustainable construction, and anticorrosive coatings.

Santoprene divestment: ExxonMobil Chemical Company sold its global *Santoprene* business to Celanese. The sale included two manufacturing sites, one in the United States and one in the United Kingdom.

Chemical Financial Results

	2021	2020	2019
		(millions of dollars)	
Earnings (loss) (U.S. GAAP)			
United States	4,502	1,277	206
Non-U.S.	3,294	686	386
Total	7,796	1,963	592
Identified Items *(1)*			
United States	494	(90)	—
Non-U.S.	136	(24)	2
Total	630	(114)	2
Earnings (loss) excluding Identified Items *(1)*			
United States	4,008	1,367	206
Non-U.S.	3,158	710	384
Total	7,166	2,077	590

(1) Refer to Frequently Used Terms for definition of Identified Items and earnings (loss) excluding Identified Items.

2021 Chemical Earnings Factor Analysis

(millions of dollars)

xom-20211231_g5.jpg

Margins – Stronger margins increased earnings by $4,480 million driven by resilient demand and industry supply constraints.

Volume – Higher volumes increased earnings by $250 million on record production supported by exceptional reliability.

Other – All other items increased earnings by $360 million primarily as a result of favorable foreign exchange, lower expenses, and favorable LIFO impacts.

Identified Items *(1)* – 2020 $(114) million loss primarily as a result of impairments; 2021 $630 million gain as a result of the *Santoprene* divestment.

2020 Chemical Earnings Factor Analysis

(millions of dollars)

xom-20211231_g6.jpg

Margins – Stronger margins increased earnings by $930 million.

Volume – Lower volumes decreased earnings by $150 million.

Other – All other items increased earnings by $710 million primarily as a result of lower expenses.

Identified Items *(1)* – 2020 $(114) million loss primarily as a result of impairments.

(1) Refer to Frequently Used Terms for definition of Identified Items and earnings (loss) excluding Identified Items.

Chemical Operational Results

	2021	2020	2019
Chemical prime product sales *(2)*	*(thousands of metric tons)*		
United States	9,724	9,010	9,127
Non-U.S.	16,608	16,439	17,389
Worldwide	26,332	25,449	26,516

(2) Data reported net of purchases/sales contracts with the same counterparty.

Corporate and Financing

Corporate and Financing is comprised of corporate activities that support the Corporation's operating segments and ExxonMobil's Low Carbon Solutions business. Corporate activities include general administrative support functions, financing and insurance activities. Low Carbon Solutions activities are included in Corporate and Financing as the business continues to mature through commercialization and deployment of technology.

Corporate and Financing Financial Results

	2021	2020	2019
		(millions of dollars)	
Earnings (loss) (U.S. GAAP)	(2,636)	(3,296)	(3,017)
Identified Items *(1)*	(64)	(361)	308
Earnings (loss) excluding Identified Items *(1)*	(2,572)	(2,935)	(3,325)

(1) Refer to Frequently Used Terms for definition of Identified Items and earnings (loss) excluding Identified Items.

2021

Corporate and Financing expenses were $2,636 million in 2021 compared to $3,296 million in 2020, with the decrease mainly due to the absence of prior year severance costs and lower financing costs.

2020

Corporate and Financing expenses were $3,296 million in 2020 compared to $3,017 million in 2019, with the increase mainly due to higher financing costs and employee severance costs, partly offset by lower corporate costs.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2021	2020	2019
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	48,129	14,668	29,716
Investing activities	(10,235)	(18,459)	(23,084)
Financing activities	(35,423)	5,285	(6,618)
Effect of exchange rate changes	(33)	(219)	33
Increase/(decrease) in cash and cash equivalents	2,438	1,275	47
		(December 31)	
Total cash and cash equivalents	6,802	4,364	3,089

Total cash and cash equivalents were $6.8 billion at the end of 2021, up $2.4 billion from the prior year. The major sources of funds in 2021 were net income including noncontrolling interests of $23.6 billion, the adjustment for the noncash provision of $20.6 billion for depreciation and depletion, contributions from operational working capital of $4.2 billion, proceeds from asset sales of $3.2 billion, and other investing activities of $1.5 billion. The major uses of funds included a debt reduction of $19.7 billion, spending for additions to property, plant and equipment of $12.1 billion, dividends to shareholders of $14.9 billion, and additional investments and advances of $2.8 billion.

Total cash and cash equivalents were $4.4 billion at the end of 2020, up $1.3 billion from the prior year. The major sources of funds in 2020 were the adjustment for the noncash provision of $46.0 billion, a net debt increase of $20.1 billion, proceeds from asset sales of $1.0 billion, and other investing activities of $2.7 billion. The major uses of funds included a net loss including noncontrolling interests of $23.3 billion, spending for additions to property, plant and equipment of $17.3 billion, dividends to shareholders of $14.9 billion, and additional investments and advances of $4.9 billion.

The Corporation has access to significant capacity of long-term and short-term liquidity. In addition to cash balances, commercial paper continues to provide short-term liquidity, and is reflected in "Notes and loans payable" on the Consolidated Balance Sheet with changes in outstanding commercial paper between periods included in the Consolidated Statement of Cash Flows. The Corporation took steps to strengthen its balance sheet in 2021, reducing debt by nearly $20 billion and ending the year with $47.7 billion in total debt. On December 31, 2021, the Corporation had undrawn short-term committed lines of credit of $10.7 billion and undrawn long-term lines of credit of $0.6 billion.

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 to eventually produce at declining rates for the remainder of their economic life. 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. In particular, the Corporation's key tight-oil plays have higher initial decline rates which tend to moderate over time. 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 mitigating 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 2021 were $16.6 billion, reflecting the Corporation's continued active investment program. The Corporation plans to invest in the range of $21 billion to $24 billion in 2022.

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 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.

The Corporation, as part of its ongoing asset management program, continues to evaluate its mix of assets for potential upgrade. Because of the ongoing nature of this program, dispositions will continue to be made from time to time which will result in either gains or losses. In light of commodity price volatility, and depending on the pace of demand recovery, the Corporation's planned divestment program could be adversely affected by fewer financially suitable buyers. This could result in a slowing of the pace of divestments, certain assets being sold at a price below current book value, or impairment charges if the likelihood of divesting certain assets increases. Additionally, the Corporation continues to evaluate opportunities to enhance its business portfolio through acquisitions of assets or companies, and enters into such transactions from time to time. Key criteria for evaluating acquisitions include potential for future growth and attractive current valuations. Acquisitions may be made with cash, shares of the Corporation's common stock, or both.

ExxonMobil closely monitors the potential impact of Interbank Offered Rate (IBOR) reform, including LIBOR, under a number of scenarios and has taken steps to mitigate the potential impact. Accordingly, ExxonMobil does not believe this event represents a material risk to the Corporation's consolidated results of operations or financial condition.

Cash Flow from Operating Activities

2021

Cash provided by operating activities totaled $48.1 billion in 2021, $33.5 billion higher than 2020. The major source of funds was net income including noncontrolling interests of $23.6 billion, an increase of $46.8 billion. The noncash provision for depreciation and depletion was $20.6 billion, down $25.4 billion from the prior year. The adjustment for the net gain on asset sales was $1.2 billion, an increase of $1.2 billion. The adjustment for dividends received less than equity in current earnings of equity companies was a reduction of $0.7 billion, compared to an increase of $1.0 billion in 2020. Changes in operational working capital, excluding cash and debt, increased cash in 2021 by $4.2 billion.

2020

Cash provided by operating activities totaled $14.7 billion in 2020, $15.0 billion lower than 2019. Net income (loss) including noncontrolling interests was a loss of $23.3 billion, a decrease of $38.0 billion. The noncash provision for depreciation and depletion was $46.0 billion, up $27.0 billion from the prior year, mainly due to asset impairments. The noncash provision for deferred income tax benefits was $8.9 billion and also included impacts from asset impairments. The adjustment for the net loss on asset sales was $4 million, a decrease of $1.7 billion. The adjustment for dividends received less than equity in current earnings of equity companies was an increase of $1.0 billion, compared to a reduction of $0.9 billion in 2019. Changes in operational working capital, excluding cash and debt, decreased cash in 2020 by $1.7 billion.

Cash Flow from Investing Activities

2021

Cash used in investing activities netted to $10.2 billion in 2021, $8.2 billion lower than 2020. Spending for property, plant and equipment of $12.1 billion decreased $5.2 billion from 2020. Proceeds from asset sales and returns of investments of $3.2 billion compared to $1.0 billion in 2020. Additional investments and advances were $2.0 billion lower in 2021, while proceeds from other investing activities including collection of advances decreased by $1.2 billion.

2020

Cash used in investing activities netted to $18.5 billion in 2020, $4.6 billion lower than 2019. Spending for property, plant and equipment of $17.3 billion decreased $7.1 billion from 2019. Proceeds from asset sales and returns of investments of $1.0 billion compared to $3.7 billion in 2019. Additional investments and advances were $1.0 billion higher in 2020, 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

2021

Cash used in financing activities was $35.4 billion in 2021, $40.7 billion higher than 2020. Dividend payments on common shares increased to $3.49 per share from $3.48 per share and totaled $14.9 billion. During 2021, the Corporation utilized cash to reduce debt by $19.7 billion.

ExxonMobil share of equity increased $11.4 billion to $168.6 billion. The addition to equity for earnings was $23.0 billion. This was offset by reductions for distributions to ExxonMobil shareholders of $14.9 billion, all in the form of dividends. Foreign exchange translation effects of $0.9 billion for the stronger U.S. dollar reduced equity and a $3.8 billion change in the funded status of the postretirement benefits reserves increased equity.

During 2021, Exxon Mobil Corporation suspended its share repurchase program used to offset shares or units settled in shares issued in conjunction with the company's benefit plans and programs. In 2022, the Corporation initiated a share repurchase program of up to $10 billion over 12 to 24 months.

2020

Cash flow from financing activities was $5.3 billion in 2020, $11.9 billion higher than 2019. Dividend payments on common shares increased to $3.48 per share from $3.43 per share and totaled $14.9 billion. During 2020, the Corporation issued $23.2 billion of long-term debt. Total debt increased $20.7 billion to $67.6 billion at year-end.

ExxonMobil share of equity decreased $34.5 billion to $157.2 billion. The reduction to equity for losses was $22.4 billion and the reduction for distributions to ExxonMobil shareholders of $14.9 billion, all in the form of dividends. Foreign exchange translation effects of $1.8 billion for the weaker U.S. dollar and a $1.0 billion change in the funded status of the postretirement benefits reserves increased equity.

During 2020, 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 4,234 million to 4,233 million at the end of 2020.

Contractual Obligations

The Corporation has contractual obligations involving commitments to third parties that impact its liquidity and capital resource needs. These contractual obligations are primarily for leases, debt, asset retirement obligations, pension and other postretirement benefits, take-or-pay and unconditional purchase obligations, and firm capital commitments. See Notes 9, 11, 14 and 17 for information related to asset retirement obligations, leases, long-term debt and pensions, respectively.

In addition, the Corporation also enters into 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. These commitments are not meaningful in assessing liquidity and cash flow, because the purchases will be offset in the same periods by cash received from the related sales transactions.

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. These obligations mainly pertain to pipeline, manufacturing supply and terminal agreements. The total obligation at year-end 2021 for take-or-pay and unconditional purchase obligations was $30,031 million. Cash payments expected in 2022 and 2023 are $4,004 million and $3,560 million, respectively.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2021 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, 2021, the Corporation had total unused short-term committed lines of credit of $10.7 billion (Note 6) and total unused long-term committed lines of credit of $0.6 billion (Note 14). The table below shows the Corporation's consolidated debt to capital ratios.

	2021	2020	2019
Debt to capital (percent)	21.4	29.2	19.1
Net debt to capital (percent)	18.9	27.8	18.1

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

Industry conditions in 2020 led to lower realized prices for the Corporation's products which resulted in substantially lower earnings and operating cash flow in comparison to 2019. The Corporation took steps to strengthen its liquidity in 2020, including issuing $23.2 billion of long-term debt and implementing significant capital and operating cost reductions. The Corporation ended 2020 with $67.6 billion in total debt.

Stronger prices and margins improved the Corporation's financial results in 2021. The Corporation reduced debt by $19.9 billion and ended the year with $47.7 billion in total debt.

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

Capital and exploration expenditures (Capex) represents the combined total of additions at cost to property, plant and equipment, and exploration expenses on a before-tax basis from the Consolidated Statement of Income. ExxonMobil's Capex includes its share of similar costs for equity companies. Capex excludes assets acquired in nonmonetary exchanges, the value of ExxonMobil shares used to acquire assets, and depreciation on the cost of exploration support equipment and facilities recorded to property, plant and equipment when acquired. While

ExxonMobil's management is responsible for all investments and elements of net income, particular focus is placed on managing the controllable aspects of this group of expenditures.

	2021			2020		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
	(millions of dollars)					
Upstream *(1)*	4,018	8,236	12,254	6,817	7,614	14,431
Downstream	1,000	1,095	2,095	2,344	1,877	4,221
Chemical	1,367	876	2,243	2,002	714	2,716
Other	3	—	3	6	—	6
Total	6,388	10,207	16,595	11,169	10,205	21,374

(1) Exploration expenses included.

Capex in 2021 was $16.6 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 plans to invest in the range of $21 billion to $24 billion in 2022. Included in the 2022 capital spend range is $8.3 billion of firm capital commitments. An additional $10.7 billion of firm capital commitments have been made for years 2023 and beyond. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $12.3 billion in 2021 was down 15 percent from 2020, primarily in the U.S. Permian Basin. Investments in 2021 included the U.S. Permian Basin and key development projects in Guyana and Brazil. 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 66 percent of total proved reserves at year-end 2021, and has been over 60 percent for the last ten years.

Capital investments in the Downstream totaled $2.1 billion in 2021, a decrease of $2.1 billion from 2020, reflecting lower global project spending. Chemical capital expenditures of $2.2 billion, decreased $0.5 billion, representing reduced spend on growth projects.

TAXES

	2021	2020	2019
		(millions of dollars)	
Income taxes	7,636	(5,632)	5,282
Effective income tax rate	*31 %*	*17 %*	*34 %*
Total other taxes and duties	32,955	28,425	33,186
Total	40,591	22,793	38,468

2021

Total taxes on the Corporation's income statement were $40.6 billion in 2021, an increase of $17.8 billion from 2020. Income tax expense, both current and deferred, was $7.6 billion compared to a $5.6 billion benefit in 2020. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 31 percent compared to 17 percent in the prior year due primarily to a change in mix of results in jurisdictions with varying tax rates. Total other taxes and duties of $33.0 billion in 2021 increased $4.5 billion.

2020

Total taxes on the Corporation's income statement were $22.8 billion in 2020, a decrease of $15.7 billion from 2019. Income tax expense, both current and deferred, was a benefit of $5.6 billion compared to $5.3 billion expense in 2019. The relative benefit was driven by asset impairments recorded in 2020. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 17 percent compared to 34 percent in the prior year due primarily to a change in mix of results in jurisdictions with varying tax rates. Total other taxes and duties of $28.4 billion in 2020 decreased $4.8 billion.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2021	2020
	(millions of dollars)	
Capital expenditures	1,202	1,087
Other expenditures	3,361	3,389
Total	4,563	4,476

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 2021 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.6 billion, of which $3.4 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $5.3 billion in 2022, with capital expenditures expected to account for approximately 30 percent of the total. Costs for 2023 are anticipated to be higher as the Low Carbon Solutions business matures and the Corporation progresses its emission-reduction plans.

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 2021 for environmental liabilities were $146 million ($263 million in 2020) and the balance sheet reflects liabilities of $807 million as of December 31, 2021, and $902 million as of December 31, 2020.

MARKET RISKS

Worldwide Average Realizations *(1)*	2021	2020	2019
Crude oil and NGL ($ per barrel)	61.89	35.41	56.32
Natural gas ($ per thousand cubic feet)	4.33	2.01	3.05

(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. For the year 2022, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $500 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 $155 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.

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 and 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. Refer to Note 18 for additional information on intersegment revenue.

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 assets are contributing to the Corporation’s strategic objectives.

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 to generate returns from trading. The Corporation’s commodity derivatives are not accounted for under hedge accounting. At times, the Corporation also enters into currency and interest rate derivatives, none of which are material to the Corporation’s financial position as of December 31, 2021 and 2020, or results of operations for the years ended 2021, 2020 and 2019. 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 or cash flow. 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 long-term and short-term debt as required. Commercial paper is used to balance short-term liquidity requirements. 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 use of these contracts are not material.

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

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; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen and biofuels. 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 oil and natural gas reserve volumes 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, development and production costs, and 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 and Resources 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 Corporation is reasonably certain that 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 policy, consumer preferences and significant changes in oil and natural gas price levels.

- 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.

Unit-of-Production Depreciation

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

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

To the extent that proved reserves for a property are 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.

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. 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 ASC 932, and relies, in part, on the Corporation's planning and budgeting cycle.

Because the lifespans of the vast majority of the Corporation's major assets are measured in decades, the future cash flows of these assets are predominantly based on long-term oil and natural gas commodity prices and industry margins, and development and production costs. Significant reductions in the Corporation's view of oil or natural gas commodity prices or margin ranges, especially the longer-term prices and margins, and changes in the development plans, including decisions to defer, reduce, or eliminate planned capital spending, can be an indicator of potential impairment. Other events or changes in circumstances, including indicators outlined in ASC 360, can be indicators of potential impairment as well.

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, alternative energy sources and levels of prosperity. During the lifespan of its major assets, the Corporation expects that oil and gas prices and industry margins 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 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 and margins.

Energy Outlook and Cash Flow Assessment. The annual planning and budgeting process, known as the Corporate Plan, is the mechanism by which resources (capital, operating expenses, and people) are allocated across the Corporation. The foundation for the assumptions supporting the Corporate Plan is the Energy Outlook, which contains the Corporation's demand and supply projections based on its assessment of current trends in technology, government policies, consumer preferences, geopolitics, and economic development. Reflective of the existing global policy environment, the Energy Outlook does not project the degree of required future policy and technology advancement and deployment for the world, or the Corporation, to meet net-zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Energy Outlook, and the Corporation's business plans will be updated accordingly.

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. Cash flows used in recoverability assessments are based on the assumptions developed in the Corporate Plan, which is reviewed and approved by the Board of Directors, 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 including price differentials, refining and chemical margins, volumes, development and operating costs including greenhouse gas emission prices, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. The greenhouse gas emission prices reflect existing or anticipated policy actions that countries or localities may take in support of Paris Accord pledges. While third-party scenarios, such as the International Energy Agency Net Zero Emissions by 2050, may be used to test the resiliency of the Corporation's businesses or strategies, they are not used as a basis for developing future cash flows for impairment assessments.

Fair Value of Impaired Assets. An asset group is impaired if its estimated undiscounted cash flows are less than the asset group's carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. The assessment of fair value is based upon the views of a likely market participant. The principal parameters used to establish fair value include estimates of acreage values and flowing production metrics from comparable market transactions, market-based estimates of historical cash flow multiples, and discounted cash flows. Inputs and assumptions used in discounted cash flow models include estimates of future production volumes, throughput and product sales volumes, commodity prices which are consistent with the average of third-party industry experts and government agencies, refining and chemical margins, drilling and development costs, operating costs and discount rates which are reflective of the characteristics of the asset group.

Other Impairment Estimates. Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the Corporation's future development plans, 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.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the assets are considered impaired and adjusted to the lower value. Judgment is required to determine if assets are held for sale and to determine the fair value less cost to sell.

Investments in equity companies are assessed for possible impairment when events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. Examples of key indicators include a history of operating losses, negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, and the financial condition and prospects for the investee's business segment or geographic region. If the decline in value of the investment is other than temporary, the carrying value of the investment is written down to fair value. In the absence of market prices for the investment, discounted cash flows are used to assess fair value, which requires significant judgment.

Recent Impairments. In 2021, the Corporation identified situations where events or changes in circumstances indicated that the carrying value of certain long-lived assets may not be recoverable and performed impairment assessments. After-tax impairment charges of $1.0 billion, including impairments of suspended wells, were recognized during the year largely as a result of changes to Upstream development plans.

In 2020, as part of the Corporation's annual review and approval of its business and strategic plan, a decision was made to no longer develop a significant portion of the dry gas portfolio in the U.S., Canada and Argentina. The impairment of these assets resulted in after-tax charges of $18.4 billion in Upstream. Other after-tax impairment charges of $1.1 billion, $0.6 billion and $0.2 billion were recognized in Upstream, Downstream and Chemical, respectively. These charges include impairments of property, plant and equipment, goodwill and equity method investments.

In 2019, after-tax impairment charges were $0.2 billion.

Factors which could put further assets at risk of impairment in the future include reductions in the Corporation's price or margin outlooks, changes in the allocation of capital or development plans, reduced long-term demand for the Corporation's products, and operating cost increases which exceed the pace of efficiencies or the pace of oil and natural gas price or margin increases. However, due to the inherent difficulty in predicting future commodity prices or margins, 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.

For further information regarding impairments in goodwill, equity method investments, property, plant and equipment and suspended wells, refer to Notes 3, 7, 9 and 10, respectively.

Asset Retirement Obligations

The Corporation is subject to 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.

Suspended Exploratory Well Costs

The Corporation continues capitalization of exploratory well costs when it has found a sufficient quantity of reserves to justify 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. Assessing whether the Corporation is making sufficient progress on a project requires careful consideration of the facts and circumstances. The facts and circumstances that support continued capitalization of suspended wells at year-end are disclosed in Note 10.

Pension Benefits

The Corporation and its affiliates sponsor about 80 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 2021 was 5.3 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 9 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 $190 million before tax.

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

Litigation and Tax Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. 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. 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.

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.

The Corporation is subject to income taxation in many jurisdictions around the world. 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. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict. The Corporation’s unrecognized tax benefits and a description of open tax years are summarized in Note 19.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation's Chief Executive Officer, Chief 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, 2021.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2021, as stated in their report included in the Financial Section of this report.

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Darren W. Woods Chief Executive Officer	Kathryn A. Mikells Senior Vice President and Chief Financial Officer	Len M. Fox 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 sheet of Exxon Mobil Corporation and its subsidiaries (the "Corporation") as of December 31, 2021 and 2020, and the related consolidated statements of income, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 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, 2021, 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.

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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Oil and Natural Gas Reserves on Upstream Property, Plant and Equipment, Net

As described in Notes 1, 9 and 18 to the consolidated financial statements, the Corporation's consolidated upstream property, plant and equipment (PP&E), net balance was $157.0 billion as of December 31, 2021, and the related depreciation and depletion expense for the year ended December 31, 2021 was $16.7 billion. Management uses the successful efforts method to account for its exploration and production activities. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. As disclosed by management, proved oil and natural gas reserve volumes are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. The estimation of proved oil and natural gas reserve volumes is an ongoing process based on technical evaluations, commercial and market assessments, and detailed analysis of well information such as flow rates and reservoir pressure declines, development and production costs, among other factors. As further disclosed by management, reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals, assisted by the Global Reserves and Resources Group (together "management's specialists").

The principal considerations for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on upstream PP&E, net is a critical audit matter are (i) the significant judgment by management, including the use of management's specialists, when developing the estimates of proved oil and natural gas reserve volumes, as the reserve volumes are based on engineering assumptions and methods, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the data, methods, and assumptions used by management and its specialists in developing the estimates of proved oil and natural gas reserve volumes and the assumptions applied to the data related to future development costs and production costs, as applicable.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and natural gas reserve volumes. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved oil and natural gas reserve volumes. As a basis for using this work, the specialists' qualifications were understood and the Corporation's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists, and an evaluation of the specialists' findings. These procedures also included, among others, testing the completeness and accuracy of the data related to future development costs and production costs. Additionally, these procedures included evaluating whether the assumptions applied to the data related to future development costs and production costs were reasonable considering the past performance of the Corporation.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 23, 2022

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

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2021	2020	2019
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue		276,692	178,574	255,583
Income from equity affiliates	7	6,657	1,732	5,441
Other income		2,291	1,196	3,914
Total revenues and other income		285,640	181,502	264,938
Costs and other deductions				
Crude oil and product purchases		155,164	94,007	143,801
Production and manufacturing expenses		36,035	30,431	36,826
Selling, general and administrative expenses		9,574	10,168	11,398
Depreciation and depletion (includes impairments)	3, 9	20,607	46,009	18,998
Exploration expenses, including dry holes		1,054	1,285	1,269
Non-service pension and postretirement benefit expense	17	786	1,205	1,235
Interest expense		947	1,158	830
Other taxes and duties	19	30,239	26,122	30,525
Total costs and other deductions		254,406	210,385	244,882
Income (loss) before income taxes		31,234	(28,883)	20,056
Income tax expense (benefit)	19	7,636	(5,632)	5,282
Net income (loss) including noncontrolling interests		23,598	(23,251)	14,774
Net income (loss) attributable to noncontrolling interests		558	(811)	434
Net income (loss) attributable to ExxonMobil		23,040	(22,440)	14,340
Earnings (loss) per common share *(dollars)*	12	5.39	(5.25)	3.36
Earnings (loss) per common share - assuming dilution *(dollars)*	12	5.39	(5.25)	3.36

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2021	2020	2019
		(millions of dollars)	
Net income (loss) including noncontrolling interests	23,598	(23,251)	14,774
Other comprehensive income (loss) (net of income taxes)			
Foreign exchange translation adjustment	(872)	1,916	1,735
Adjustment for foreign exchange translation (gain)/loss included in net income	(2)	14	—
Postretirement benefits reserves adjustment (excluding amortization)	3,118	30	(2,092)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	925	896	582
Total other comprehensive income (loss)	3,169	2,856	225
Comprehensive income (loss) including noncontrolling interests	26,767	(20,395)	14,999
Comprehensive income (loss) attributable to noncontrolling interests	786	(743)	588
Comprehensive income (loss) attributable to ExxonMobil	25,981	(19,652)	14,411

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	December 31, 2021	December 31, 2020
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		6,802	4,364
Notes and accounts receivable - net	6	32,383	20,581
Inventories			
Crude oil, products and merchandise	3	14,519	14,169
Materials and supplies		4,261	4,681
Other current assets		1,189	1,098
Total current assets		59,154	44,893
Investments, advances and long-term receivables	8	45,195	43,515
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	216,552	227,553
Other assets, including intangibles - net		18,022	16,789
Total assets		338,923	332,750
Liabilities			
Current liabilities			
Notes and loans payable	6	4,276	20,458
Accounts payable and accrued liabilities	6	50,766	35,221
Income taxes payable		1,601	684
Total current liabilities		56,643	56,363
Long-term debt	14	43,428	47,182
Postretirement benefits reserves	17	18,430	22,415
Deferred income tax liabilities	19	20,165	18,165
Long-term obligations to equity companies		2,857	3,253
Other long-term obligations		21,717	21,242
Total liabilities		163,240	168,620
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		15,746	15,688
Earnings reinvested		392,059	383,943
Accumulated other comprehensive income		(13,764)	(16,705)
Common stock held in treasury (3,780 million shares in 2021 and 3,786 million shares in 2020)		(225,464)	(225,776)
ExxonMobil share of equity		168,577	157,150
Noncontrolling interests		7,106	6,980
Total equity		175,683	164,130
Total liabilities and equity		338,923	332,750

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2021	2020	2019
		(millions of dollars)		
Cash flows from operating activities				
Net income (loss) including noncontrolling interests		23,598	(23,251)	14,774
Adjustments for noncash transactions				
Depreciation and depletion (includes impairments)	3, 9	20,607	46,009	18,998
Deferred income tax charges/(credits)	19	303	(8,856)	(944)
Postretirement benefits expense in excess of/(less than) net payments		754	498	109
Other long-term obligation provisions in excess of/(less than) payments		50	(1,269)	(3,038)
Dividends received greater than/(less than) equity in current earnings of equity companies		(668)	979	(936)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		(12,098)	5,384	(2,640)
- Inventories		(489)	(315)	72
- Other current assets		(71)	420	(234)
Increase/(reduction) - Accounts and other payables		16,820	(7,142)	3,725
Net (gain)/loss on asset sales	5	(1,207)	4	(1,710)
All other items - net		530	2,207	1,540
Net cash provided by operating activities		48,129	14,668	29,716
Cash flows from investing activities				
Additions to property, plant and equipment		(12,076)	(17,282)	(24,361)
Proceeds from asset sales and returns of investments		3,176	999	3,692
Additional investments and advances		(2,817)	(4,857)	(3,905)
Other investing activities including collection of advances		1,482	2,681	1,490
Net cash used in investing activities		(10,235)	(18,459)	(23,084)
Cash flows from financing activities				
Additions to long-term debt		46	23,186	7,052
Reductions in long-term debt		(8)	(8)	(1)
Additions to short-term debt *(1)*		12,687	35,396	18,967
Reductions in short-term debt *(1)*		(29,396)	(28,742)	(18,367)
Additions/(reductions) in commercial paper, and debt with three months or less maturity		(2,983)	(9,691)	1,011
Contingent consideration payments		(30)	(21)	—
Cash dividends to ExxonMobil shareholders		(14,924)	(14,865)	(14,652)
Cash dividends to noncontrolling interests		(224)	(188)	(192)
Changes in noncontrolling interests		(436)	623	158
Common stock acquired		(155)	(405)	(594)
Net cash provided by (used in) financing activities		(35,423)	5,285	(6,618)
Effects of exchange rate changes on cash		(33)	(219)	33
Increase/(decrease) in cash and cash equivalents		2,438	1,275	47
Cash and cash equivalents at beginning of year		4,364	3,089	3,042
Cash and cash equivalents at end of year		6,802	4,364	3,089

(1) Includes commercial paper with a maturity greater than three months.

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	Total Equity
				(millions of dollars)			
Balance as of December 31, 2018	15,258	421,653	(19,564)	(225,553)	191,794	6,734	198,528
Amortization of stock-based awards	697	—	—	—	697	—	697
Other	(318)	—	—	—	(318)	489	171
Net income (loss) for the year	—	14,340	—	—	14,340	434	14,774
Dividends - common shares	—	(14,652)	—	—	(14,652)	(192)	(14,844)
Other comprehensive income	—	—	71	—	71	154	225
Acquisitions, at cost	—	—	—	(594)	(594)	(331)	(925)
Dispositions	—	—	—	312	312	—	312
Balance as of December 31, 2019	15,637	421,341	(19,493)	(225,835)	191,650	7,288	198,938
Amortization of stock-based awards	696	—	—	—	696	—	696
Other	(645)	—	—	—	(645)	692	47
Net income (loss) for the year	—	(22,440)	—	—	(22,440)	(811)	(23,251)
Dividends - common shares	—	(14,865)	—	—	(14,865)	(188)	(15,053)
Cumulative effect of accounting change	—	(93)	—	—	(93)	(1)	(94)
Other comprehensive income	—	—	2,788	—	2,788	68	2,856
Acquisitions, at cost	—	—	—	(405)	(405)	(68)	(473)
Dispositions	—	—	—	464	464	—	464
Balance as of December 31, 2020	15,688	383,943	(16,705)	(225,776)	157,150	6,980	164,130
Amortization of stock-based awards	534	—	—	—	534	—	534
Other	(476)	—	—	—	(476)	115	(361)
Net income (loss) for the year	—	23,040	—	—	23,040	558	23,598
Dividends - common shares	—	(14,924)	—	—	(14,924)	(224)	(15,148)
Other comprehensive income	—	—	2,941	—	2,941	228	3,169
Acquisitions, at cost	—	—	—	(155)	(155)	(551)	(706)
Dispositions	—	—	—	467	467	—	467
Balance as of December 31, 2021	15,746	392,059	(13,764)	(225,464)	168,577	7,106	175,683

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2018	8,019	(3,782)	4,237
Acquisitions	—	(8)	(8)
Dispositions	—	5	5
Balance as of December 31, 2019	8,019	(3,785)	4,234
Acquisitions	—	(8)	(8)
Dispositions	—	7	7
Balance as of December 31, 2020	8,019	(3,786)	4,233
Acquisitions	—	(2)	(2)
Dispositions	—	8	8
Balance as of December 31, 2021	8,019	(3,780)	4,239

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

The Corporation's principal business involves exploration for, and production of, crude oil and natural gas; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen and biofuels.

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years' data have been reclassified in certain cases to conform to the 2021 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation and Accounting for Investments

The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses. Amounts representing the Corporation's interest in entities that it does not control, but over which it exercises significant influence, are included in "Investments, advances and long-term receivables". The Corporation's share of the net income of these companies is included in the Consolidated Statement of Income caption "Income from equity affiliates".

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

Investments in equity companies are assessed for possible impairment when events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. Examples of key indicators include a history of operating losses, negative earnings and cash flow outlook, significant downward revisions to oil and gas reserves, and the financial condition and prospects for the investee's business segment or geographic region. If the decline in value of the investment is other than temporary, the carrying value of the investment is written down to fair value. In the absence of market prices for the investment, discounted cash flows are used to assess fair value.

Investments in equity securities other than consolidated subsidiaries and equity method investments are measured at fair value with changes in fair value recognized in net income. The Corporation uses the modified approach for equity securities that do not have a readily determinable fair value. This modified approach measures investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions in a similar investment of the same issuer.

The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in "Accumulated other comprehensive income".

Revenue Recognition

The Corporation generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments to reflect market conditions. Revenue is recognized at the amount the Corporation expects to receive when the customer has taken control, which is typically when title transfers and the customer has assumed the risks and rewards of ownership. The prices of certain sales are based on price indices that are sometimes not available until the next period. In such cases, estimated realizations are accrued when the sale is recognized, and are finalized when the price is available. Such adjustments to revenue from performance obligations satisfied in previous periods are not significant. Payment for revenue transactions is typically due within 30 days. Future volume delivery obligations that are unsatisfied at the end of the period are expected to be fulfilled through ordinary production or purchases. These performance obligations are based on market prices at the time of the transaction and are fully constrained due to market price volatility.

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

"Sales and other operating revenue" and "Notes and accounts receivable" primarily arise from contracts with customers. Long-term receivables are primarily from non-customers. Contract assets are mainly from marketing assistance programs and are not significant. Contract liabilities are mainly customer prepayments and accruals of expected volume discounts and are not significant.

Income and Other Taxes

The Corporation excludes from the Consolidated Statement of Income certain sales and value-added taxes imposed on and concurrent with revenue-producing transactions with customers and collected on behalf of governmental authorities. Similar taxes, for which the Corporation is not considered to be an agent for the government, are reported on a gross basis (included in both “Sales and other operating revenue” and “Other taxes and duties”).

The Corporation accounts for U.S. tax on global intangible low-taxed income as an income tax expense in the period in which it is incurred.

Derivative Instruments

The Corporation may use derivative instruments for trading purposes and to offset exposures associated with commodity prices, foreign currency exchange rates and interest rates that arise from existing assets, liabilities, firm commitments and forecasted transactions. All derivative instruments, except those designated as normal purchase and normal sale, are recorded at fair value. Derivative assets and liabilities with the same counterparty are netted if the right of offset exists and certain other criteria are met. Collateral payables or receivables are netted against derivative assets and derivative liabilities, respectively.

Recognition and classification of the gain or loss that results from adjusting a derivative to fair value depends on the purpose for the derivative. All gains and losses from derivative instruments for which the Corporation does not apply hedge accounting are immediately recognized in earnings. The Corporation may designate derivatives as fair value or cash flow hedges. For fair value hedges, the gain or loss from derivative instruments and the offsetting gain or loss from the hedged item are recognized in earnings. For cash flow hedges, the gain or loss from the derivative instrument is initially reported as a component of other comprehensive income and subsequently reclassified into earnings in the period that the forecasted transaction affects earnings.

Fair Value

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

Inventories

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

Property, Plant and Equipment

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

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

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

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

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.

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

Impairment Assessment. The Corporation tests assets or groups of assets for recoverability 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.

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 ASC 932, and relies in part on the Corporation's planning and budgeting cycle. Asset valuation analysis, profitability reviews and other periodic control processes assist the Corporation in assessing whether events or changes in circumstances indicate the carrying amounts of any of its assets may not be recoverable.

Because the lifespans of the vast majority of the Corporation's major assets are measured in decades, the future cash flows of these assets are predominantly based on long-term oil and natural gas commodity prices, industry margins, and development and production costs. Significant reductions in the Corporation's view of oil or natural gas commodity prices or margin ranges, especially the longer-term prices and margins, and changes in the development plans, including decisions to defer, reduce, or eliminate planned capital spending, can be an indicator of potential impairment. Other events or changes in circumstances, can be indicators of potential impairment as well.

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, alternative energy sources and levels of prosperity. During the lifespan of its major assets, the Corporation expects that oil and gas prices and industry margins 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 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 and margins.

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 in the year. These prices represent discrete points in time and could be higher or lower than the Corporation's 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.

Energy Outlook and Cash Flow Assessment. The annual planning and budgeting process, known as the Corporate Plan, is the mechanism by which resources (capital, operating expenses, and people) are allocated across the Corporation. The foundation for the assumptions supporting the Corporate Plan is the Energy Outlook, which contains the Corporation’s demand and supply projections based on its assessment of current trends in technology, government policies, consumer preferences, geopolitics, and economic development. Reflective of the existing global policy environment, the Energy Outlook does not project the degree of required future policy and technology advancement and deployment for the world, or the Corporation, to meet net-zero by 2050. As future policies and technology advancements emerge, they will be incorporated into the Energy Outlook, and the Corporation’s business plans will be updated accordingly.

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 assumptions which are developed in the Corporate Plan, which is reviewed and approved by the Board of Directors, 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 including price differentials, refining and chemical margins, volumes, development and operating costs including greenhouse gas emission prices, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management’s estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. The greenhouse gas emission prices reflect existing or anticipated policy actions that countries or localities may take in support of Paris Accord pledges. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

Fair value of Impaired Assets. An asset group is impaired if its estimated undiscounted cash flows are less than the asset group's carrying value. Impairments are measured by the amount by which the carrying value exceeds fair value. The assessment of fair value is based upon the views of a likely market participant. The principal parameters used to establish fair value include estimates of acreage values and flowing production metrics from comparable market transactions, market-based estimates of historical cash flow multiples, and discounted cash flows. Inputs and assumptions used in discounted cash flow models include estimates of future production volumes, throughput and product sales volumes, commodity prices which are consistent with the average of third-party industry experts and government agencies, refining and chemical margins, drilling and development costs, operating costs and discount rates which are reflective of the characteristics of the asset group.

Other Impairments Related to Property, Plant and Equipment. Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the Corporation's future development plans, 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.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the assets are considered impaired and adjusted to the lower value. Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any substantial obligation for future performance by the Corporation.

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

Environmental Liabilities

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

Foreign Currency Translation

The Corporation selects the functional reporting currency for its international subsidiaries based on the currency of the primary economic environment in which each subsidiary operates. Downstream and Chemical operations primarily use the local currency. However, the U.S. dollar is used in countries with a history of high inflation (primarily in Latin America) and Singapore, which predominantly sells into the U.S. dollar export market. Upstream operations which are relatively self-contained and integrated within a particular country, such as in Canada and Europe, use the local currency. Some Upstream operations, primarily in Asia and Africa, use the U.S. dollar because they predominantly sell crude and natural gas production into U.S. dollar-denominated markets.

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

2. Restructuring Activities

During 2020, ExxonMobil conducted an extensive global review of staffing levels and subsequently commenced targeted workforce reductions within a number of countries to improve efficiency and reduce costs. The programs were completed by the end of 2021 and included both voluntary and involuntary employee separations as well as reductions in contractors.

In 2021, the Corporation recorded before-tax charges of $58 million, consisting primarily of employee separation costs, associated with announced workforce reduction programs in Singapore and Europe. These costs are captured in “Selling, general and administrative expenses” on the Consolidated Statement of Income and reported within Corporate and Financing. The Corporation does not expect any further charges related to the previously disclosed workforce reduction programs.

The following table summarizes the reserves and charges related to the workforce reduction programs announced in late 2020 and early 2021. These are recorded in “Accounts payable and accrued liabilities” on the Consolidated Balance Sheet and do not include charges related to employee reductions associated with any portfolio changes or other projects.

	2021	2020
	(millions of dollars)	
Beginning Balance	403	—
Additions/adjustments	58	450
Payments made	(384)	(47)
Ending Balance	77	403

The cash outflows associated with the remaining liability balance of $77 million at December 31, 2021 will occur over the next few years, mainly in the form of monthly payments.

3. Miscellaneous Financial Information

Research and development expenses totaled $843 million in 2021, $1,016 million in 2020, and $1,214 million in 2019.

Net income included before-tax aggregate foreign exchange transaction losses of $18 million, $24 million and $104 million in 2021, 2020 and 2019, respectively.

In 2021, 2020, and 2019, net income included gains of $54 million, $41 million, and $523 million, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $14.0 billion and $5.4 billion at December 31, 2021, and 2020, respectively.

Crude oil, products and merchandise as of year-end 2021 and 2020 consist of the following:

	Dec 31, 2021	Dec 31, 2020
	(millions of dollars)	
Crude oil	4,162	5,354
Petroleum products	5,081	5,138
Chemical products	3,354	3,023
Gas/other	1,922	654
Total	14,519	14,169

Mainly as a result of declines in prices for crude oil, natural gas and petroleum products and a significant decline in its market capitalization at the end of the first quarter of 2020, the Corporation recognized before-tax goodwill impairment charges of $611 million in Upstream, Downstream, and Chemical reporting units. Fair value of the goodwill reporting units primarily reflected market-based estimates of historical EBITDA multiples at the end of the first quarter. Charges related to goodwill impairments in 2020 are included in “Depreciation and depletion” on the Consolidated Statement of Income.

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	**Cumulative Foreign Exchange Translation Adjustment**	**Postretirement Benefits Reserves Adjustment**	**Total**
		(millions of dollars)	
Balance as of December 31, 2018	(13,881)	(5,683)	(19,564)
Current period change excluding amounts reclassified from accumulated other comprehensive income	1,435	(1,927)	(492)
Amounts reclassified from accumulated other comprehensive income	—	563	563
Total change in accumulated other comprehensive income	1,435	(1,364)	71
Balance as of December 31, 2019	(12,446)	(7,047)	(19,493)
Current period change excluding amounts reclassified from accumulated other comprehensive income *(1)*	1,818	95	1,913
Amounts reclassified from accumulated other comprehensive income	14	861	875
Total change in accumulated other comprehensive income	1,832	956	2,788
Balance as of December 31, 2020	(10,614)	(6,091)	(16,705)

(1) Cumulative Foreign Exchange Translation Adjustment includes net investment hedge gain/(loss) net of taxes of $329 million and $(355) million in 2021 and 2020, respectively.

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/ (Expense)	**2021**	**2020**	**2019**
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	2	(14)	—
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs (Statement of Income line: Non-service pension and postretirement benefit expense)	(1,229)	(1,158)	(751)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	**2021**	**2020**	**2019**
		(millions of dollars)	
Foreign exchange translation adjustment	(114)	118	88
Postretirement benefits reserves adjustment (excluding amortization)	(983)	109	719
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(304)	(262)	(169)
Total	(1,401)	(35)	638

5. Cash Flow Information

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

For 2021, the “Net (gain)/loss on asset sales” on the Consolidated Statement of Cash Flows includes before-tax amounts from the sale of non-operated upstream assets in the United Kingdom Central and Northern North Sea and the sale of ExxonMobil's global *Santoprene* business. The United Kingdom Central and Northern North Sea assets were sold to Neo Energy, resulting in a before-tax gain of $0.4 billion and cash proceeds of $0.7 billion in 2021. The *Santoprene* business, including two chemical manufacturing sites in Pensacola, Florida and Newport, Wales, was sold to Celanese, resulting in a before-tax gain of $0.8 billion and cash proceeds of $1.1 billion in 2021. For 2019, the “Net (gain)/loss on asset sales” line includes before-tax amounts from the sale of non-operated upstream assets in Norway and upstream asset transactions in the U.S. The Norway assets were sold for $4.5 billion, resulting in a gain of $3.7 billion and cash proceeds of $3.1 billion in 2019.

For 2020, the “Depreciation and depletion” and “Deferred income tax charges/(credits)” on the Consolidated Statement of Cash Flows include impacts from asset impairments, primarily in Upstream.

	2021	2020	2019
		(millions of dollars)	
Income taxes paid	5,341	2,428	7,018
Cash interest paid			
Included in cash flows from operating activities	819	786	560
Capitalized, included in cash flows from investing activities	655	665	731
Total cash interest paid	1,474	1,451	1,291

6. Additional Working Capital Information

	Dec 31, 2021	Dec 31, 2020
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $159 million and $96 million	26,883	16,339
Other, less reserves of $381 million and $378 million	5,500	4,242
Total	32,383	20,581
Notes and loans payable		
Bank loans	276	222
Commercial paper	1,608	17,306
Long-term debt due within one year	2,392	2,930
Total	4,276	20,458
Accounts payable and accrued liabilities		
Trade payables	26,623	17,499
Payables to equity companies	8,885	6,476
Accrued taxes other than income taxes	3,896	3,408
Other	11,362	7,838
Total	50,766	35,221

The Corporation has short-term committed lines of credit of $10.7 billion which were unused as of December 31, 2021. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 0.2 percent and 0.2 percent at December 31, 2021, and 2020, respectively.

7. Equity Company Information

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

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 10 percent, 11 percent and 13 percent in the years 2021, 2020 and 2019, respectively.

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

Impairments related to upstream equity investments of $0.2 billion and $0.6 billion in 2021 and 2020, respectively, are included in "Income from equity affiliates" or "Other income" on the Consolidated Statement of Income.

	2021		2020		2019	
Equity Company Financial Summary	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**
			(millions of dollars)			
Total revenues	116,972	34,995	69,954	21,282	102,365	31,240
Income before income taxes	35,142	9,278	12,743	2,830	29,424	7,927
Income taxes	11,010	2,763	4,333	870	9,725	2,500
Income from equity affiliates	24,132	6,515	8,410	1,960	19,699	5,427
Current assets	45,267	15,542	33,419	11,969	36,035	12,661
Long-term assets	150,699	41,614	150,358	41,457	143,321	40,001
Total assets	195,966	57,156	183,777	53,426	179,356	52,662
Current liabilities	28,862	8,297	18,827	5,245	24,583	6,939
Long-term liabilities	63,138	19,084	66,053	19,927	61,022	18,158
Net assets	103,966	29,775	98,897	28,254	93,751	27,565

A list of significant equity companies as of December 31, 2021, together with the Corporation’s percentage ownership interest, is detailed below:

	Percenta Ownersh Interes
Upstream	
Aera Energy LLC	48
Barzan Gas Company Limited	7
BEB Erdgas und Erdoel GmbH & Co. KG	50
Caspian Pipeline Consortium	8
CORAL FLNG, S.A.	25
Cross Timbers Energy, LLC	50
GasTerra B.V.	25
Golden Pass LNG Terminal LLC	30
Golden Pass Pipeline LLC	30
Marine Well Containment Company LLC	10
Mozambique Rovuma Venture, S.p.A.	36
Nederlandse Aardolie Maatschappij B.V.	50
Papua New Guinea Liquefied Natural Gas Global Company LDC	33
Permian Highway Pipeline LLC	20
Qatar Liquefied Gas Company Limited	10
Qatar Liquefied Gas Company Limited (2)	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited (II)	31
Ras Laffan Liquefied Natural Gas Company Limited (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	71
Downstream	
Alberta Products Pipe Line Ltd.	45
Fujian Refining & Petrochemical Co. Ltd.	25
Permian Express Partners LLC	12
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Gulf Coast Growth Ventures LLC	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec 31, 2021	Dec 31, 2020
	(millions of dollars)	
Equity method company investments and advances		
Investments	31,225	29,772
Advances, net of allowances of $34 million and $31 million	8,326	8,812
Total equity method company investments and advances	39,551	38,584
Equity securities carried at fair value and other investments at adjusted cost basis	138	143
Long-term receivables and miscellaneous, net of reserves of $5,974 million and $6,115 million	5,506	4,788
Total	45,195	43,515

9. Property, Plant and Equipment and Asset Retirement Obligations

	December 31, 2021		December 31, 2020	
Property, Plant and Equipment	Cost	Net	Cost	Net
	(millions of dollars)			
Upstream	375,813	156,951	386,614	167,472
Downstream	57,947	27,417	57,922	27,716
Chemical	43,288	21,793	42,868	21,924
Other	18,014	10,391	17,918	10,441
Total	495,062	216,552	505,322	227,553

In 2021, the Corporation identified situations where events or changes in circumstances indicated that the carrying value of certain long-lived assets may not be recoverable and performed impairment assessments. Before-tax impairment charges of $1.2 billion, including impairments of suspended wells, were recognized during the year largely as a result of changes to Upstream development plans.

In 2020, as part of the Corporation's annual review and approval of its business and strategic plan, a decision was made to no longer develop a significant portion of the dry gas portfolio in the U.S., Canada and Argentina. The impairment of these assets resulted in before-tax charges of $24.4 billion in Upstream. Other before-tax impairment charges in 2020 included $0.9 billion in Upstream, $0.5 billion in Downstream, and $0.1 billion in Chemical. In 2019, before-tax impairment charges were $0.1 billion.

Impairment charges are primarily recognized in the lines “Depreciation and depletion” and “Exploration expenses, including dry holes” on the Consolidated Statement of Income. Accumulated depreciation and depletion totaled $278,510 million at the end of 2021 and $277,769 million at the end of 2020.

Asset Retirement Obligations

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

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

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

	2021	2020	2019
		(millions of dollars)	
Balance at January 1	11,247	11,280	12,103
Accretion expense and other provisions	548	584	649
Reduction due to property sales	(1,002)	(77)	(1,085)
Payments made	(444)	(669)	(827)
Liabilities incurred	42	26	89
Foreign currency translation	(147)	239	84
Revisions	386	(136)	267
Balance at December 31	10,630	11,247	11,280

The long-term Asset Retirement Obligations were $9,985 million and $10,558 million at December 31, 2021, and 2020, respectively, and are included in “Other long-term obligations” on the Consolidated Balance Sheet. Estimated cash payments in 2022 and 2023 are $645 million and $648 million, respectively.

10. Accounting for Suspended Exploratory Well Costs

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

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

Change in capitalized suspended exploratory well costs:	2021	2020	2019
		(millions of dollars)	
Balance beginning at January 1	4,382	4,613	4,160
Additions pending the determination of proved reserves	420	208	532
Charged to expense	(325)	(318)	(46)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(328)	(174)	(37)
Divestments/ Other	(29)	53	4
Ending balance at December 31	4,120	4,382	4,613
Ending balance attributed to equity companies included above	306	306	306

Period end capitalized suspended exploratory well costs:	2021	2020	2019
		(millions of dollars)	
Capitalized for a period of one year or less	420	208	532
Capitalized for a period of between one and five years	1,642	1,828	2,206
Capitalized for a period of between five and ten years	1,657	1,932	1,411
Capitalized for a period of greater than ten years	401	414	464
Capitalized for a period greater than one year - subtotal	3,700	4,174	4,081
Total	4,120	4,382	4,613

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a breakdown of the number of projects with only exploratory well costs capitalized for a period of one year or less and those that have had exploratory well costs capitalized for a period greater than one year.

	2021	2020	2019
Number of projects that only have exploratory well costs capitalized for a period of one year or less	4	3	4
Number of projects that have exploratory well costs capitalized for a period greater than one year	30	34	46
Total	34	37	50

Of the 30 projects that have exploratory well costs capitalized for a period greater than one year as of December 31, 2021, 13 projects have drilling in the preceding year or exploratory activity planned in the next two years, while the remaining 17 projects are those with completed exploratory activity progressing toward development.

The table below provides additional detail for those 17 projects, which total $2,874 million.

Country/Project	Dec. 31, 2021	Years Wells Drilled / Acquired	Comment
(millions of dollars)			
Argentina			
– La Invernada	72	2014	Evaluating development plan to tie into planned infrastructure.
Australia			
– Gorgon Area Ullage	327	1994 -2015	Evaluating development plans to tie into existing LNG facilities.
Canada			
– Hibernia North	26	2019	Awaiting capacity in existing/planned infrastructure.
Guyana			
– Yellowtail	138	2019 -2020	Continuing discussions with the government regarding development plan.
Kazakhstan			
– Kairan	53	2004 -2007	Evaluating commercialization and field development alternatives, while continuing discussions with the government regarding the development plan.
Mozambique			
– Rovuma LNG Future Non-Straddling Train	120	2017	Evaluating/progressing development plan to tie into planned LNG facilities.
– Rovuma LNG Phase 1	150	2017	Progressing development plan to tie into planned LNG facilities.
– Rovuma LNG Unitized Trains	35	2017	Evaluating/progressing development plan to tie into planned LNG facilities.
Nigeria			
– Bonga North	34	2004 -2009	Evaluating/progressing development plan for tieback to existing/ planned infrastructure.
– Bonga SW	3	2001	Evaluating/progressing development plan for tieback to existing/ planned infrastructure.
– Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
Papua New Guinea			
– Muruk	165	2017 -2019	Evaluating/progressing development plans.
– Papua LNG	246	2017	Evaluating/progressing development plans.
– P'nyang	116	2012 -2018	Evaluating/progressing development plans.
Romania			
– Neptun Deep	536	2012 -2016	Continuing discussions with the government regarding development plan.
Tanzania			
– Tanzania Block 2	525	2012 -2015	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
Vietnam			
– Blue Whale	296	2011 -2015	Evaluating/progressing development plans.
Total 2021 (17 projects)	2,874		

11. Leases

The Corporation and its consolidated affiliates generally purchase the property, plant and equipment used in operations, but there are situations where assets are leased, primarily for drilling equipment, tankers, office buildings, railcars, and other moveable equipment. Right of use assets and lease liabilities are established on the balance sheet for leases with an expected term greater than one year by discounting the amounts fixed in the lease agreement for the duration of the lease which is reasonably certain, considering the probability of exercising any early termination and extension options. The portion of the fixed payment related to service costs for drilling equipment, tankers and finance leases is excluded from the calculation of right of use assets and lease liabilities. Generally, assets are leased only for a portion of their useful lives, and are accounted for as operating leases. In limited situations assets are leased for nearly all of their useful lives, and are accounted for as finance leases.

Variable payments under these lease agreements are not significant. Residual value guarantees, restrictions, or covenants related to leases, and transactions with related parties are also not significant. In general, leases are capitalized using the incremental borrowing rate of the leasing affiliate. The Corporation's activities as a lessor are not significant.

	Operating Leases			Finance Leases		
Lease Cost	**2021**	**2020**	**2019**	**2021**	**2020**	**2019**
			(millions of dollars)			
Operating lease cost	1,542	1,553	1,434			
Short-term and other (net of sublease rental income)	1,351	1,613	2,042			
Amortization of right of use assets				133	143	121
Interest on lease liabilities				158	169	133
Total *(1)*	2,893	3,166	3,476	291	312	254

(1) Includes $681 million, $827 million and $1,164 million for drilling rigs and related equipment operating leases in 2021, 2020 and 2019, respectively.

Balance Sheet	Operating Leases December 31, 2021	Operating Leases December 31, 2020	Finance Leases December 31, 2021	Finance Leases December 31, 2020
	(millions of dollars)			
Right of use assets				
Included in Other assets, including intangibles - net	6,082	6,078		
Included in Property, plant and equipment - net			2,412	2,188
Total right of use assets	6,082	6,078	2,412	2,188
Lease liability due within one year				
Included in Accounts payable and accrued liabilities	1,367	1,168	4	4
Included in Notes and loans payable			111	102
Long-term lease liability				
Included in Other long-term obligations	3,823	3,994		
Included in Long-term debt			1,761	1,680
Included in Long-term obligations to equity companies			131	135
Total lease liability *(2)*	5,190	5,162	2,007	1,921
Weighted average remaining lease term (years)	10	11	20	20
Weighted average discount rate (percent)	2.3 %	2.9 %	7.7 %	8.9 %

(2) Includes $935 million and $832 million for drilling rigs and related equipment operating leases in 2021 and 2020, respectively.

Maturity Analysis of Lease Liabilities	Operating Leases	Finance Leases
	December 31, 2021	
	(millions of dollars)	
2022	1,456	262
2023	1,141	256
2024	574	253
2025	437	246
2026	384	382
2027 and beyond	1,978	2,111
Total lease payments	5,970	3,510
Discount to present value	(780)	(1,503)
Total lease liability	5,190	2,007

In addition to the lease liabilities in the table immediately above, at December 31, 2021, undiscounted commitments for leases not yet commenced totaled $962 million for operating leases and $4,960 million for finance leases. Estimated cash payments for operating and finance leases not yet commenced are $310 million and $415 million for 2022 and 2023 respectively. The finance leases relate to floating production storage and offloading vessels, LNG transportation vessels, and a long-term hydrogen purchase agreement. The underlying assets for these finance leases were primarily designed by, and are being constructed by, the lessors.

	Operating Leases			Finance Leases		
Other Information	2021	2020	2019	2021	2020	2019
	(millions of dollars)					
Cash paid for amounts included in the measurement of lease liabilities						
Cash flows from operating activities	1,135	1,159	1,116	20	31	54
Cash flows from investing activities	291	283	258			
Cash flows from financing activities				110	94	177
Noncash right of use assets recorded for lease liabilities						
For January 1 adoption of ASC 842			3,263			
In exchange for lease liabilities during the period	1,405	735	3,663	200	108	422

12. Earnings Per Share

Earnings per common share	**2021**	**2020**	**2019**
Net income (loss) attributable to ExxonMobil *(millions of dollars)*	23,040	(22,440)	14,340
Weighted average number of common shares outstanding *(millions of shares)*	4,275	4,271	4,270
Earnings (loss) per common share *(dollars) (1)*	5.39	(5.25)	3.36
Dividends paid per common share *(dollars)*	3.49	3.48	3.43

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

13. Financial Instruments and Derivatives

Financial Instruments. The estimated fair value of financial instruments at December 31, 2021 and December 31, 2020, and the related hierarchy level for the fair value measurement is as follows:

	December 31, 2021							
	(millions of dollars)							
	Fair Value							
	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets *(1)*	1,422	1,523	—	2,945	(1,930)	(28)	—	987
Advances to/receivables from equity companies *(2)(6)*	—	3,076	5,373	8,449	—	—	(123)	8,326
Other long-term financial assets *(3)*	1,134	—	1,058	2,192	—	—	181	2,373
Liabilities								
Derivative liabilities *(4)*	1,701	2,594	—	4,295	(1,930)	(306)	—	2,059
Long-term debt *(5)*	44,454	88	3	44,545	—	—	(2,878)	41,667
Long-term obligations to equity companies *(6)*	—	—	3,084	3,084	—	—	(227)	2,857
Other long-term financial liabilities *(7)*	—	—	902	902	—	—	58	960

	December 31, 2020							
	(millions of dollars)							
	Fair Value							
	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets *(1)*	1,247	194	—	1,441	(1,282)	(6)	—	153
Advances to/receivables from equity companies *(2)(6)*	—	3,275	5,904	9,179	—	—	(367)	8,812
Other long-term financial assets *(3)*	1,235	—	944	2,179	—	—	125	2,304
Liabilities								
Derivative liabilities *(4)*	1,443	254	—	1,697	(1,282)	(202)	—	213
Long-term debt *(5)*	50,263	125	4	50,392	—	—	(4,890)	45,502
Long-term obligations to equity companies *(6)*	—	—	3,530	3,530	—	—	(277)	3,253
Other long-term financial liabilities *(7)*	—	—	964	964	—	—	44	1,008

(1) Included in the Balance Sheet lines: Notes and accounts receivable - net and Other assets, including intangibles - net

(2) Included in the Balance Sheet line: Investments, advances and long-term receivables

(3) Included in the Balance Sheet lines: Investments, advances and long-term receivables and Other assets, including intangibles - net

(4) Included in the Balance Sheet lines: Accounts payable and accrued liabilities and Other long-term obligations

(5) Excluding finance lease obligations

(6) Advances to/receivables from equity companies and long-term obligations to equity companies are mainly designated as hierarchy level 3 inputs. The fair value is calculated by discounting the remaining obligations by a rate consistent with the credit quality and industry of the company.

(7) Included in the Balance Sheet line: Other long-term obligations. Includes contingent consideration related to a prior year acquisition where fair value is based on expected drilling activities and discount rates.

At December 31, 2021 and December 31, 2020, the Corporation had $641 million and $504 million of collateral under master netting arrangements not offset against the derivatives on the Consolidated Balance Sheet, primarily related to initial margin requirements.

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in 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. Commodity contracts held for trading purposes are presented in the Consolidated Statement of Income on a net basis in the line "Sales and other operating revenue". The Corporation's commodity derivatives are not accounted for under hedge accounting. At times, the Corporation also enters into currency and interest rate derivatives, none of which are material to the Corporation's financial position as of December 31, 2021 and 2020, or results of operations for 2021, 2020 and 2019.

Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

The net notional long/(short) position of derivative instruments at December 31, 2021 and December 31, 2020, was as follows:

	December 31, 2021	December 31, 2020
	(millions)	
Crude oil (barrels)	82	40
Petroleum products (barrels)	(48)	(46)
Natural gas (MMBTUs)	(115)	(500)

Realized and unrealized gains/(losses) on derivative instruments that were recognized in the Consolidated Statement of Income are included in the following lines on a before-tax basis:

	2021	2020	2019
		(millions of dollars)	
Sales and other operating revenue	(3,818)	404	(412)
Crude oil and product purchases	48	(407)	179
Total	(3,770)	(3)	(233)

14. Long-Term Debt

At December 31, 2021, long-term debt consisted of $37,611 million due in U.S. dollars and $5,817 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $2,392 million, which matures within one year and is included in current liabilities.

On December 17, 2021, the Corporation irrevocably deposited sufficient cash with the Trustee to fund the redemption of its 2.397% notes due 2022. After the deposit of the funds, the Corporation was released from its obligation and the debt was extinguished.

The amounts of long-term debt, excluding finance lease obligations, maturing in each of the four years after December 31, 2022, in millions of dollars, are: 2023 – $4,039; 2024 – $3,836; 2025 – $4,597; and 2026 – $3,575. At December 31, 2021, the Corporation's unused long-term lines of credit were $0.6 billion.

The Corporation may use non-derivative financial instruments, such as its foreign currency-denominated debt, as hedges of its net investments in certain foreign subsidiaries. Under this method, the change in the carrying value of the financial instruments due to foreign exchange fluctuations is reported in accumulated other comprehensive income. As of December 31, 2021, the Corporation has designated its $5.1 billion of Euro-denominated long-term debt and related accrued interest as a net investment hedge of its European business. The net investment hedge is deemed to be perfectly effective.

Summarized long-term debt at year-end 2021 and 2020 are shown in the table below:

	Average Rate *(1)*	Dec 31, 2021	Dec 31, 2020
		(millions of dollars)	
Exxon Mobil Corporation *(2)*			
2.397% notes due 2022		—	1,150
1.902% notes due 2022		—	750
Floating-rate notes due 2022 *(Issued 2015)*		—	500
Floating-rate notes due 2022 *(Issued 2019)*		—	750
1.571% notes due 2023		2,750	2,750
2.726% notes due 2023		1,250	1,250
3.176% notes due 2024		1,000	1,000
2.019% notes due 2024		1,000	1,000
2.709% notes due 2025		1,750	1,750
2.992% notes due 2025		2,794	2,807
3.043% notes due 2026		2,500	2,500
2.275% notes due 2026		1,000	1,000
3.294% notes due 2027		1,000	1,000
2.440% notes due 2029		1,250	1,250
3.482% notes due 2030		2,000	2,000
2.610% notes due 2030		2,000	2,000
2.995% notes due 2039		750	750
4.227% notes due 2040		2,087	2,091
3.567% notes due 2045		1,000	1,000
4.114% notes due 2046		2,500	2,500
3.095% notes due 2049		1,500	1,500
4.327% notes due 2050		2,750	2,750
3.452% notes due 2051		2,750	2,750
Exxon Mobil Corporation - Euro-denominated			
0.142% notes due 2024		1,698	1,841
0.524% notes due 2028		1,133	1,227
0.835% notes due 2032		1,133	1,227
1.408% notes due 2039		1,133	1,227
XTO Energy Inc. *(3)*			
6.100% senior notes due 2036		191	192
6.750% senior notes due 2037		291	294
6.375% senior notes due 2038		226	227
Industrial revenue bonds due 2022-2051	0.028%	2,244	2,461
Other U.S. dollar obligations		64	78
Other foreign currency obligations		37	61
Finance lease obligations	7.438%	1,761	1,680
Debt issuance costs		(114)	(131)
Total long-term debt		43,428	47,182

(1) Average effective interest rate for debt and average imputed interest rate for finance leases at December 31, 2021.

(2) Includes premiums of $131 million in 2021 and $148 million in 2020.

(3) Includes premiums of $82 million in 2021 and $87 million in 2020.

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock, and other forms of awards. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire, or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2021, remaining shares available for award under the 2003 Incentive Program were 66 million.

Restricted Stock and Restricted Stock Units. Awards totaling 8,133 thousand, 8,681 thousand, and 8,936 thousand of restricted (nonvested) common stock units were granted in 2021, 2020, and 2019, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years for the remaining 50 percent of the award, except that for awards granted prior to 2020 the vesting of the 10-year portion of the award is delayed until retirement if later than 10 years.

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2021.

	2021	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	39,585	80.43
Awards issued in 2021	8,753	41.29
Vested	(9,142)	86.16
Forfeited	(274)	66.54
Issued and outstanding at December 31	38,922	70.38

Value of restricted stock units	**2021**	**2020**	**2019**
Grant price *(dollars)*	62.76	41.15	68.77
Value at date of grant:		*(millions of dollars)*	
Units settled in stock	461	325	559
Units settled in cash	49	32	55
Total value	510	357	614

As of December 31, 2021, there was $1,268 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.4 years. The compensation cost charged against income for the restricted stock and restricted stock units was $612 million, $672 million, and $741 million for 2021, 2020, and 2019, respectively. The income tax benefit recognized in income related to this compensation expense was $49 million, $51 million, and $51 million for the same periods, respectively. The fair value of shares and units vested in 2021, 2020, and 2019 was $562 million, $367 million, and $647 million, respectively. Cash payments of $48 million, $34 million, and $56 million for vested restricted stock units settled in cash were made in 2021, 2020, and 2019, respectively.

16. Litigation and Other Contingencies

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

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2021, for guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management’s estimate of the maximum potential exposure.

	December 31, 2021		
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	1,109	140	1,249
Other	775	6,498	7,273
Total	1,884	6,638	8,522

(1) ExxonMobil share.

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

The Corporation has previously provided disclosure regarding (i) claims being pursued by the Corporation against the Venezuelan National Oil Company in connection with a 2007 Venezuelan nationalization decree, and (ii) claims being pursued by the Corporation against the Nigerian National Petroleum Corporation in connection with a dispute involving crude oil lifting entitlements which was originally subject to arbitration in 2011. Both matters remain ongoing but, as previously disclosed, the Corporation does not expect the ultimate resolution of either matter to have a material effect upon the Corporation’s operations or financial condition. In the interest of disclosure simplification, the Corporation will no longer include specific disclosure of these matters in its annual or quarterly reports unless future developments alter the foregoing conclusions.

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2021	2020	2021	2020	2021	2020
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	3.00	2.80	2.20	1.60	3.10	2.80
Long-term rate of compensation increase	4.50	5.50	4.20	4.20	4.50	5.50
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	21,662	20,959	33,626	29,918	8,135	8,113
Service cost	919	965	774	707	188	181
Interest cost	558	708	526	657	221	277
Actuarial loss/(gain) *(1)*	(747)	1,287	(2,803)	2,344	(881)	(66)
Benefits paid *(2) (3)*	(3,810)	(1,987)	(1,550)	(1,317)	(517)	(510)
Foreign exchange rate changes	—	—	(1,162)	1,375	3	23
Amendments, divestments and other	(71)	(270)	81	(58)	116	117
Benefit obligation at December 31	18,511	21,662	29,492	33,626	7,265	8,135
Accumulated benefit obligation at December 31	15,781	17,502	27,373	30,952	—	—

(1) Actuarial loss/(gain) primarily reflects changes in discount rates, lower long-term rates of compensation and a lower health care cost trend rate.

(2) Benefit payments for funded and unfunded plans.

(3) For 2021 and 2020, other postretirement benefits paid are net of $9 million and $16 million of Medicare subsidy receipts, respectively.

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the effective discount rate determined by use of a yield curve based on high-quality, noncallable bonds applied to the estimated cash outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using a spot yield curve of high-quality, local-currency-denominated bonds at an average maturity approximating that of the liabilities.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.0 percent in 2023 and subsequent years.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2021	2020	2021	2020	2021	2020
	(millions of dollars)					
Change in plan assets						
Fair value at January 1	15,300	13,636	26,216	22,916	446	425
Actual return on plan assets	479	2,269	571	2,795	20	42
Foreign exchange rate changes	—	—	(605)	1,011	—	—
Company contribution	794	1,004	293	597	28	37
Benefits paid *(1)*	(3,307)	(1,609)	(1,167)	(992)	(54)	(58)
Other	—	—	(428)	(111)	—	—
Fair value at December 31	13,266	15,300	24,880	26,216	440	446

(1) Benefit payments for funded plans.

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2021	2020	2021	2020
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(3,570)	(4,156)	554	(1,223)
Unfunded plans	(1,675)	(2,206)	(5,166)	(6,187)
Total	(5,245)	(6,362)	(4,612)	(7,410)

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2021	2020	2021	2020	2021	2020
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(5,245)	(6,362)	(4,612)	(7,410)	(6,825)	(7,689)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	—	—	2,544	1,931	—	—
Current liabilities	(206)	(377)	(267)	(273)	(323)	(327)
Postretirement benefits reserves	(5,039)	(5,985)	(6,889)	(9,068)	(6,502)	(7,362)
Total recorded	(5,245)	(6,362)	(4,612)	(7,410)	(6,825)	(7,689)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	1,865	3,102	2,841	5,904	197	1,164
Prior service cost	(324)	(275)	262	208	(232)	(274)
Total recorded in accumulated other comprehensive income	1,541	2,827	3,103	6,112	(35)	890

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

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

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2021	2020	2019	2021	2020	2019	2021	2020	2019
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					*(percent)*				
Discount rate	2.80	3.50	4.40	1.60	2.30	3.00	2.80	3.50	4.40
Long-term rate of return on funded assets	5.30	5.30	5.30	4.10	4.10	4.10	4.60	4.60	4.60
Long-term rate of compensation increase	5.50	5.75	5.75	4.20	4.80	4.30	5.50	5.75	5.75
Components of net periodic benefit cost					*(millions of dollars)*				
Service cost	919	965	757	774	707	551	188	181	139
Interest cost	558	708	766	526	657	763	221	277	315
Expected return on plan assets	(722)	(703)	(568)	(1,031)	(897)	(777)	(19)	(18)	(15)
Amortization of actuarial loss/(gain)	244	310	305	420	416	306	76	95	55
Amortization of prior service cost	(23)	5	5	57	68	56	(42)	(42)	(42)
Net pension enhancement and curtailment/ settlement cost	489	280	164	32	49	(98)	—	—	—
Net periodic benefit cost	1,465	1,565	1,429	778	1,000	801	424	493	452
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	(504)	(279)	609	(2,361)	446	1,268	(891)	(92)	517
Amortization of actuarial (loss)/gain	(733)	(590)	(469)	(430)	(442)	(208)	(76)	(95)	(55)
Prior service cost/(credit)	(72)	(271)	—	92	(82)	379	—	—	—
Amortization of prior service (cost)/credit	23	(5)	(5)	(55)	(68)	(56)	42	42	42
Foreign exchange rate changes	—	—	—	(255)	236	19	—	11	—
Total recorded in other comprehensive income	(1,286)	(1,145)	135	(3,009)	90	1,402	(925)	(134)	504
Total recorded in net periodic benefit cost and other comprehensive income, before tax	179	420	1,564	(2,231)	1,090	2,203	(501)	359	956

Costs for defined contribution plans were \$177 million, \$358 million and \$422 million in 2021, 2020 and 2019, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2021	2020	2019
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	1,286	1,145	(135)
Non-U.S. pension	3,009	(90)	(1,402)
Other postretirement benefits	925	134	(504)
Total (charge)/ credit to other comprehensive income, before tax	5,220	1,189	(2,041)
(Charge)/credit to income tax (see Note 4)	(1,287)	(153)	550
(Charge)/credit to investment in equity companies	110	(110)	(19)
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	4,043	926	(1,510)
Charge/(credit) to equity of noncontrolling interests	(217)	30	146
(Charge)/credit to other comprehensive income attributable to ExxonMobil	3,826	956	(1,364)

The Corporation's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in plan assets and liabilities and broad diversification to reduce the risk of the portfolio. The benefit plan assets are primarily invested in passive global equity and local currency fixed income index funds to diversify risk while minimizing costs. The equity funds hold ExxonMobil stock only to the extent necessary to replicate the relevant equity index. The fixed income funds are largely invested in investment grade corporate and government debt securities with interest rate sensitivity designed to approximate the interest rate sensitivity of plan liabilities.

Target asset allocations for benefit plans are reviewed periodically and set based on considerations such as risk, diversification, liquidity and funding level. The target asset allocations for the major benefit plans range from 10 to 30 percent in equity securities and the remainder in fixed income securities. The equity for the U.S. and certain non-U.S. plans include allocations to private equity partnerships that primarily focus on early-stage venture capital of less than 5 percent.

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

The 2021 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2021, Using:					Fair Value Measurement at December 31, 2021, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total	Level 1	Level 2	Level 3	Net Asset Value	Total
	(millions of dollars)									
Asset category:										
Equity securities										
U.S.	—	—	—	1,956	1,956	—	—	—	3,416	3,416
Non-U.S.	—	—	—	1,290	1,290	76 (1)	—	—	2,424	2,500
Private equity	—	—	—	661	661	—	—	—	627	627
Debt securities										
Corporate	—	5,242 (2)	—	1	5,243	—	119 (2)	—	5,831	5,950
Government	—	3,945 (2)	—	2	3,947	209 (3)	97 (2)	—	11,620	11,926
Asset-backed	—	—	—	1	1	—	25 (2)	—	191	216
Cash	—	—	—	162	162	62	53 (4)	—	108	223
Total at fair value	—	9,187	—	4,073	13,260	347	294	—	24,217	24,858
Insurance contracts at contract value					6					22
Total plan assets					13,266					24,880

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2021, Using:				
	Level 1	**Level 2**	**Level 3**	**Net Asset Value**	**Total**
	(millions of dollars)				
Asset category:					
Equity securities					
U.S.	91 (1)	—	—	—	91
Non-U.S.	45 (1)	—	—	—	45
Debt securities					
Corporate	—	95 (2)	—	—	95
Government	—	206 (2)	—	—	206
Asset-backed	—	—	—	—	—
Cash	—	3	—	—	3
Total at fair value	136	304	—	—	440

(1) For equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

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

The 2020 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2020, Using:					Fair Value Measurement at December 31, 2020, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total	Level 1	Level 2	Level 3	Net Asset Value	Total
					(millions of dollars)					
Asset category:										
Equity securities										
U.S.	—	—	—	2,323	2,323	—	—	—	4,177	4,177
Non-U.S.	—	—	—	1,703	1,703	89 *(1)*	—	—	3,285	3,374
Private equity	—	—	—	548	548	—	—	—	530	530
Debt securities										
Corporate	—	5,146 *(2)*	—	1	5,147	—	138 *(2)*	—	5,212	5,350
Government	—	5,261 *(2)*	—	2	5,263	250 *(3)*	116 *(2)*	—	11,993	12,359
Asset-backed	—	—	—	1	1	—	24 *(2)*	—	239	263
Cash	—	—	—	308	308	69	21 *(4)*	—	50	140
Total at fair value	—	10,407	—	4,886	15,293	408	299	—	25,486	26,193
Insurance contracts at contract value					7					23
Total plan assets					15,300					26,216

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2020, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total
	(millions of dollars)				
Asset category:					
Equity securities					
U.S.	88 (1)	—	—	—	88
Non-U.S.	48 (1)	—	—	—	48
Debt securities					
Corporate	—	103 (2)	—	—	103
Government	—	204 (2)	—	—	204
Asset-backed	—	—	—	—	—
Cash	—	—	—	3	3
Total at fair value	136	307	—	3	446

(1) For equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

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

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2021	2020	2021	2020
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Accumulated benefit obligation	14,511	16,129	3,108	4,602
Fair value of plan assets	13,266	15,300	1,711	2,652
For funded pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	16,836	19,456	4,840	13,836
Fair value of plan assets	13,266	15,300	2,849	10,681
For unfunded pension plans:				
Projected benefit obligation	1,675	2,206	5,166	6,187
Accumulated benefit obligation	1,270	1,373	4,685	5,469

All other postretirement benefit plans are unfunded or underfunded.

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2022	640	405	—	—
Benefit payments expected in:				
2022	1,306	1,173	423	21
2023	1,188	1,176	414	22
2024	1,179	1,205	409	23
2025	1,157	1,173	405	24
2026	1,154	1,155	396	25
2027 - 2031	5,803	6,145	1,981	132

18. Disclosures about Segments and Related Information

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

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

Earnings after income tax include transfers at estimated market prices.

In Corporate and Financing, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense of $103 million in 2021, $148 million in 2020 and $105 million in 2019.

	Upstream		Downstream		Chemical		Corporate and	Corporate
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	Financing	Total
				(millions of dollars)				
As of December 31, 2021								
Earnings (loss) after income tax	3,663	12,112	1,314	791	4,502	3,294	(2,636)	23,040
Earnings of equity companies included above	288	5,535	122	74	(139)	1,131	(354)	6,657
Sales and other operating revenue	8,883	12,914	80,044	137,963	15,309	21,549	30	276,692
Intersegment revenue	16,692	33,405	21,622	27,065	9,639	6,047	227	—
Depreciation and depletion expense	6,831	9,918	724	1,031	578	650	875	20,607
Interest revenue	—	—	—	—	—	—	33	33
Interest expense	58	36	1	7	—	1	844	947
Income tax expense (benefit)	1,116	4,871	379	160	1,476	688	(1,054)	7,636
Additions to property, plant and equipment	3,308	5,308	997	983	548	739	658	12,541
Investments in equity companies	4,999	18,544	352	888	3,020	3,759	(337)	31,225
Total assets	67,294	141,978	27,436	39,630	19,069	20,653	22,863	338,923
As of December 31, 2020								
Earnings (loss) after income tax	(19,385)	(645)	(852)	(225)	1,277	686	(3,296)	(22,440)
Effect of asset impairments - noncash	*(17,138)*	*(2,287)*	*(15)*	*(609)*	*(100)*	*(69)*	*(35)*	*(20,253)*
Earnings of equity companies included above	(559)	2,101	134	(190)	(21)	651	(384)	1,732
Sales and other operating revenue	5,876	8,673	48,256	92,640	8,529	14,562	38	178,574
Intersegment revenue	8,508	19,642	12,258	15,162	6,099	3,881	221	—
Depreciation and depletion expense	28,627	12,723	716	1,672	685	694	892	46,009
Interest revenue	—	—	—	—	—	—	49	49
Interest expense	52	93	1	21	—	—	991	1,158
Income tax expense (benefit)	(5,958)	742	(324)	393	440	272	(1,197)	(5,632)
Additions to property, plant and equipment	5,726	4,418	2,983	1,731	1,221	592	671	17,342
Investments in equity companies	4,792	18,135	352	879	2,543	3,514	(443)	29,772
Total assets	71,287	144,730	23,754	34,848	17,839	20,220	20,072	332,750
As of December 31, 2019								
Earnings (loss) after income tax	536	13,906	1,717	606	206	386	(3,017)	14,340
Earnings of equity companies included above	282	4,534	196	19	(4)	818	(404)	5,441
Sales and other operating revenue	9,364	13,779	70,523	134,460	9,723	17,693	41	255,583
Intersegment revenue	10,893	30,864	22,416	24,775	7,864	5,905	224	—
Depreciation and depletion expense	6,162	9,305	674	832	555	621	849	18,998
Interest revenue	—	—	—	—	—	—	84	84
Interest expense	54	34	1	9	—	1	731	830
Income tax expense (benefit)	(151)	5,509	465	361	58	305	(1,265)	5,282
Additions to property, plant and equipment	10,404	7,347	2,685	1,777	1,344	589	758	24,904
Investments in equity companies	5,313	17,736	319	1,062	1,835	3,335	(309)	29,291
Total assets	95,750	151,181	23,442	37,133	16,544	20,376	18,171	362,597

Geographic

Sales and other operating revenue	**2021**	**2020**	**2019**
		(millions of dollars)	
United States	104,236	62,663	89,612
Non-U.S.	172,456	115,911	165,971
Total	276,692	178,574	255,583
Significant non-U.S. revenue sources include: *(1)*			
Canada	22,166	13,093	19,735
Singapore	15,031	9,442	12,128
United Kingdom	14,759	11,055	17,479
France	13,236	8,676	12,740
Italy	10,056	7,091	10,459
Belgium	9,153	6,231	11,644
Australia	7,646	5,839	7,941

(1) Revenue is determined by primary country of operations. Excludes certain sales and other operating revenues in Non-U.S. operations where attribution to a specific country is not practicable.

Long-lived assets	December 31, 2021	2020	2019
	(millions of dollars)		
United States	90,412	94,732	114,372
Non-U.S.	126,140	132,821	138,646
Total	216,552	227,553	253,018
Significant non-U.S. long-lived assets include:			
Canada	34,907	36,232	39,130
Australia	12,988	14,792	13,933
Singapore	11,969	12,129	11,645
Kazakhstan	8,463	8,882	9,315
Papua New Guinea	7,534	7,803	8,057
United Arab Emirates	5,392	5,381	5,262
Nigeria	5,235	6,345	7,640
Guyana	4,892	3,547	2,542
Brazil	4,337	3,281	3,338
Russia	4,055	4,616	5,135
Angola	3,207	4,405	5,784

19. Income and Other Taxes

	2021			2020			2019		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
					(millions of dollars)				
Income tax expense (benefit)									
Federal and non-U.S.									
Current	236	6,948	7,184	262	2,908	3,170	(121)	6,171	6,050
Deferred - net	870	(914)	(44)	(6,045)	(2,007)	(8,052)	(255)	(420)	(675)
U.S. tax on non-U.S. operations	26	—	26	13	—	13	89	—	89
Total federal and non-U.S.	1,132	6,034	7,166	(5,770)	901	(4,869)	(287)	5,751	5,464
State	470	—	470	(763)	—	(763)	(182)	—	(182)
Total income tax expense (benefit)	1,602	6,034	7,636	(6,533)	901	(5,632)	(469)	5,751	5,282
All other taxes and duties									
Other taxes and duties	3,731	26,508	30,239	3,108	23,014	26,122	3,566	26,959	30,525
Included in production and manufacturing expenses	1,589	674	2,263	1,148	663	1,811	1,385	811	2,196
Included in SG&A expenses	170	283	453	164	328	492	160	305	465
Total other taxes and duties	5,490	27,465	32,955	4,420	24,005	28,425	5,111	28,075	33,186
Total	7,092	33,499	40,591	(2,113)	24,906	22,793	4,642	33,826	38,468

The above provisions for deferred income taxes include net benefits of $53 million in 2021, $25 million in 2020, and $740 million in 2019 related to changes in tax laws and rates, and a benefit of $6.3 billion in 2020 related to asset impairments.

The reconciliation between income tax expense (credit) and a theoretical U.S. tax computed by applying a rate of 21 percent for 2021, 2020 and 2019 is as follows:

	2021	2020	2019
		(millions of dollars)	
Income (loss) before income taxes			
United States	9,478	(27,704)	(53)
Non-U.S.	21,756	(1,179)	20,109
Total	31,234	(28,883)	20,056
Theoretical tax	6,559	(6,065)	4,212
Effect of equity method of accounting	(1,398)	(364)	(1,143)
Non-U.S. taxes in excess of/(less than) theoretical U.S. tax *(1)(2)*	2,809	1,606	2,573
State taxes, net of federal tax benefit *(1)*	371	(603)	(144)
Other	(705)	(206)	(216)
Total income tax expense (credit)	7,636	(5,632)	5,282
Effective tax rate calculation			
Income tax expense (credit)	7,636	(5,632)	5,282
ExxonMobil share of equity company income taxes	2,756	861	2,490
Total income tax expense (credit)	10,392	(4,771)	7,772
Net income (loss) including noncontrolling interests	23,598	(23,251)	14,774
Total income (loss) before taxes	33,990	(28,022)	22,546
Effective income tax rate	31 %	17 %	34 %

(1) 2020 includes the impact of an increase in valuation allowance of $647 million in non-U.S. and $115 million in U.S. state jurisdictions.

(2) 2019 includes taxes less than the theoretical U.S. tax of $773 million from Norway operations and the sale of upstream assets, $657 million from a tax rate change in Alberta, Canada, and $268 million from an adjustment to a prior year tax position.

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

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

Tax effects of temporary differences for:	2021	2020
	(millions of dollars)	
Property, plant and equipment	27,888	28,778
Other liabilities	6,353	6,427
Total deferred tax liabilities	34,241	35,205
Pension and other postretirement benefits	(3,687)	(4,703)
Asset retirement obligations	(2,865)	(3,150)
Tax loss carryforwards	(6,914)	(8,982)
Other assets	(7,694)	(7,095)
Total deferred tax assets	(21,160)	(23,930)
Asset valuation allowances	2,634	2,731
Net deferred tax liabilities	15,715	14,006

In 2021, asset valuation allowances of $2,634 million decreased by $97 million and included net provisions of $41 million and foreign currency effects of $137 million.

Balance sheet classification	2021	2020
	(millions of dollars)	
Other assets, including intangibles, net	(4,450)	(4,159)
Deferred income tax liabilities	20,165	18,165
Net deferred tax liabilities	15,715	14,006

The Corporation's undistributed earnings from subsidiary companies outside the United States include amounts that have been retained to fund prior and future capital project expenditures. Deferred income taxes have not been recorded for potential future tax obligations, such as foreign withholding tax and state tax, as these undistributed earnings are expected to be indefinitely reinvested for the foreseeable future. As of December 31, 2021, it is not practicable to estimate the unrecognized deferred tax liability. However, unrecognized deferred taxes on remittance of these funds are not expected to be material.

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

Gross unrecognized tax benefits	**2021**	**2020**	**2019**
		(millions of dollars)	
Balance at January 1	8,764	8,844	9,174
Additions based on current year's tax positions	358	253	287
Additions for prior years' tax positions	100	218	120
Reductions for prior years' tax positions	(79)	(201)	(97)
Reductions due to lapse of the statute of limitations	(2)	(237)	(279)
Settlements with tax authorities	(11)	(113)	(538)
Foreign exchange effects/other	—	—	177
Balance at December 31	9,130	8,764	8,844

The gross unrecognized tax benefit balances are predominantly related to tax positions that would reduce the Corporation’s effective tax rate if the positions are favorably resolved. Unfavorable resolution of these tax positions generally would not increase the effective tax rate. The 2021, 2020 and 2019 changes in unrecognized tax benefits did not have a material effect on the Corporation’s net income.

Resolution of these tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. It is difficult to predict the timing of resolution for these tax positions since the timing is not entirely within the control of the Corporation. In the United States, the Corporation has various ongoing U.S. federal income tax positions at issue with the Internal Revenue Service (IRS) for tax years beginning in 2006. The Corporation filed a refund suit for tax years 2006-2009 in U.S. federal district court (District Court) with respect to the positions at issue for those years. These positions are reflected in the unrecognized tax benefits table. On February 24, 2020, the Corporation received an adverse ruling on this suit. The IRS has asserted penalties associated with several of those positions. The Corporation has not recognized the penalties as an expense because the Corporation does not expect the penalties to be sustained under applicable law. On January 13, 2021, the District Court ruled that no penalties apply to the Corporation's positions in this suit. The Corporation and the government have appealed the District Court's rulings to the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit). Proceedings in the Fifth Circuit are continuing. Unfavorable resolution of all positions at issue with the IRS would not have a material adverse effect on the Corporation’s operations or financial condition.

It is reasonably possible that the total amount of unrecognized tax benefits could increase by up to 10 percent or decrease by up to 70 percent in the next 12 months. Such a decrease would result primarily from final resolution of the U.S. federal income tax litigation within this timeframe.

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

Country of Operation	**Open Tax Years**		
Abu Dhabi	2020	—	2021
Angola	2018	—	2021
Australia	2010	—	2021
Belgium	2017	—	2021
Canada	2001	—	2021
Equatorial Guinea	2007	—	2021
Indonesia	2008	—	2021
Iraq	2016	—	2021
Malaysia	2017	—	2021
Nigeria	2006	—	2021
Papua New Guinea	2008	—	2021
Russia	2019	—	2021
United Kingdom	2015	—	2021
United States	2006	—	2021

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

For 2021 and 2019 the Corporation's net interest expense was $0 million on income tax reserves. For 2020, the Corporation's net interest expense was a credit of $6 million. The related interest payable balances were $61 million at both December 31, 2021 and 2020.

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, gains and losses from derivative activity, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $(1,380) million in 2021, $274 million in 2020 and $3,502 million in 2019. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2021 - Revenue							
Sales to third parties	5,797	2,480	1,628	253	2,110	3,182	15,450
Transfers	10,938	8,492	412	6,087	8,829	812	35,570
	16,735	10,972	2,040	6,340	10,939	3,994	51,020
Production costs excluding taxes	3,436	4,867	754	1,759	1,471	481	12,768
Exploration expenses	19	464	26	359	146	40	1,054
Depreciation and depletion	6,185	2,690	408	2,799	1,965	1,002	15,049
Taxes other than income	1,367	113	11	490	1,258	423	3,662
Related income tax	1,276	55	235	311	3,858	610	6,345
Results of producing activities for consolidated subsidiaries	4,452	2,783	606	622	2,241	1,438	12,142
Equity Companies							
2021 - Revenue							
Sales to third parties	620	—	1,332	—	12,239	—	14,191
Transfers	479	—	33	—	151	—	663
	1,099	—	1,365	—	12,390	—	14,854
Production costs excluding taxes	538	—	1,065	11	413	—	2,027
Exploration expenses	—	—	2	—	—	—	2
Depreciation and depletion	509	—	194	—	611	—	1,314
Taxes other than income	33	—	48	—	3,749	—	3,830
Related income tax	—	—	13	3	2,652	—	2,668
Results of producing activities for equity companies	19	—	43	(14)	4,965	—	5,013
Total results of operations	4,471	2,783	649	608	7,206	1,438	17,155

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2020 - Revenue							
Sales to third parties	2,933	1,034	536	262	1,632	1,983	8,380
Transfers	4,943	3,938	362	4,603	5,584	509	19,939
	7,876	4,972	898	4,865	7,216	2,492	28,319
Production costs excluding taxes	3,877	3,928	786	1,911	1,471	483	12,456
Exploration expenses	51	573	33	371	112	145	1,285
Depreciation and depletion	27,489	5,118	828	2,788	2,171	733	39,127
Taxes other than income	615	106	32	390	692	152	1,987
Related income tax	(5,650)	(944)	(343)	(258)	2,130	241	(4,824)
Results of producing activities for consolidated subsidiaries	(18,506)	(3,809)	(438)	(337)	640	738	(21,712)
Equity Companies							
2020 - Revenue							
Sales to third parties	410	—	513	—	6,289	—	7,212
Transfers	308	—	12	—	60	—	380
	718	—	525	—	6,349	—	7,592
Production costs excluding taxes	500	—	674	6	421	—	1,601
Exploration expenses	—	—	2	—	—	—	2
Depreciation and depletion	605	—	224	—	543	—	1,372
Taxes other than income	34	—	22	—	2,274	—	2,330
Related income tax	—	—	(246)	(1)	1,126	—	879
Results of producing activities for equity companies	(421)	—	(151)	(5)	1,985	—	1,408
Total results of operations	(18,927)	(3,809)	(589)	(342)	2,625	738	(20,304)
Consolidated Subsidiaries							
2019 - Revenue							
Sales to third parties	5,070	1,452	2,141	802	2,393	3,132	14,990
Transfers	6,544	5,979	1,345	7,892	8,706	628	31,094
	11,614	7,431	3,486	8,694	11,099	3,760	46,084
Production costs excluding taxes	4,697	4,366	1,196	2,387	1,597	637	14,880
Exploration expenses	120	498	118	234	119	180	1,269
Depreciation and depletion	5,916	1,975	601	3,019	2,264	703	14,478
Taxes other than income	998	122	113	682	1,182	250	3,347
Related income tax	(29)	(423)	(20)	1,188	4,238	599	5,553
Results of producing activities for consolidated subsidiaries	(88)	893	1,478	1,184	1,699	1,391	6,557
Equity Companies							
2019 - Revenue							
Sales to third parties	664	—	1,248	—	10,536	—	12,448
Transfers	530	—	6	—	464	—	1,000

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $12,005 million less at year-end 2021 and $13,206 million less at year-end 2020 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
Consolidated Subsidiaries								
As of December 31, 2021								
Property (acreage) costs	– Proved	18,353	3,844	10	1,422	2,994	730	27,353
	– Unproved	21,146	6,231	37	119	5	2,675	30,213
Total property costs		39,499	10,075	47	1,541	2,999	3,405	57,566
Producing assets		101,211	52,092	14,420	56,168	44,228	14,944	283,063
Incomplete construction		4,125	7,047	889	1,428	2,888	2,044	18,421
Total capitalized costs		144,835	69,214	15,356	59,137	50,115	20,393	359,050
Accumulated depreciation and depletion		86,830	28,428	13,790	49,312	26,519	9,225	214,104
Net capitalized costs for consolidated subsidiaries		58,005	40,786	1,566	9,825	23,596	11,168	144,946
Equity Companies								
As of December 31, 2021								
Property (acreage) costs	– Proved	98	—	4	309	—	—	411
	– Unproved	4	—	—	3,111	—	—	3,115
Total property costs		102	—	4	3,420	—	—	3,526
Producing assets		6,946	—	5,487	—	8,676	—	21,109
Incomplete construction		103	—	23	809	11,716	—	12,651
Total capitalized costs		7,151	—	5,514	4,229	20,392	—	37,286
Accumulated depreciation and depletion		4,304	—	5,162	—	6,590	—	16,056
Net capitalized costs for equity companies		2,847	—	352	4,229	13,802	—	21,230
Consolidated Subsidiaries								
As of December 31, 2020								
Property (acreage) costs	– Proved	18,059	2,151	51	1,332	2,979	771	25,343
	– Unproved	23,255	7,352	37	213	181	2,642	33,680
Total property costs		41,314	9,503	88	1,545	3,160	3,413	59,023
Producing assets		104,650	52,552	20,286	55,556	43,394	15,348	291,786
Incomplete construction		5,549	4,590	1,446	1,975	3,050	1,972	18,582
Total capitalized costs		151,513	66,645	21,820	59,076	49,604	20,733	369,391
Accumulated depreciation and depletion		89,401	26,635	19,193	46,567	24,701	8,628	215,125
Net capitalized costs for consolidated		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2021 were $9,877 million, down $1,377 million from 2020, due primarily to lower development costs, partially offset by higher acquisition costs of unproved properties. In 2020, costs were $11,254 million, down $7,986 million from 2019, due primarily to lower development costs including lower asset retirement obligation cost estimates mainly in Angola. Total equity company costs incurred in 2021 were $1,451 million, down $561 million from 2020, due primarily to lower development costs.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
		(millions of dollars)						
During 2021								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	37	—	—	90	15	—	142
	– Unproved	78	575	—	—	—	35	688
Exploration costs		19	903	46	185	47	40	1,240
Development costs		3,352	2,619	207	389	805	435	7,807
Total costs incurred for consolidated subsidiaries		3,486	4,097	253	664	867	510	9,877
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		—	—	1	—	—	—	1
Development costs		8	—	20	88	1,334	—	1,450
Total costs incurred for equity companies		8	—	21	88	1,334	—	1,451
During 2020								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	1	30	—	344	7	—	382
	– Unproved	80	3	—	47	—	—	130
Exploration costs		60	702	40	232	110	83	1,227
Development costs		5,675	2,059	316	(239)	974	730	9,515
Total costs incurred for consolidated subsidiaries		5,816	2,794	356	384	1,091	813	11,254
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		—	—	2	—	—	—	2
Development costs		135	—	20	71	1,784	—	2,010
Total costs incurred for equity companies		135	—	22	71	1,784	—	2,012
During 2019								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	12	—	—	—	26	—	38
	– Unproved	226	105	1	20	—	—	352
Exploration costs		134	1,107	155	252	111	194	1,953
Development costs		10,275	2,946	809	1,066	1,317	484	16,897
Total costs incurred for consolidated subsidiaries		10,647	4,158	965	1,338	1,454	678	19,240
Equity Companies								
Property acquisition								

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2019, 2020 and 2021.

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

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

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

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

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

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

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The production and reserves reported for these types of arrangements typically vary inversely with oil and natural gas price changes. As oil and natural gas prices increase, the cash flow and value received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total proved reserves (consolidated subsidiaries plus equity companies) at year-end 2021 that were associated with production sharing contract arrangements was 12 percent on an oil-equivalent basis (natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels).

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

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

The changes between 2021 year-end proved reserves and 2020 year-end proved reserves reflect upward revisions of 2.4 billion barrels of bitumen at Kearl and 0.5 billion barrels of bitumen at Cold Lake, primarily as a result of improved prices. In addition, extensions and discoveries of approximately 1.3 billion oil-equivalent barrels (GOEB) occurred primarily in the United States (0.9 GOEB), Brazil (0.2 GOEB) and Guyana (0.1 GOEB). Worldwide production in 2021 was 1.4 GOEB.

The downward revisions in 2020, primarily as a result of low prices during 2020, include 3.1 billion barrels of bitumen at Kearl, 0.6 billion barrels of bitumen at Cold Lake, and 0.5 GOEB in the United States. In addition, the Corporation’s near-term reduction in capital expenditures resulted in a net reduction to estimates of proved reserves of approximately 1.5 GOEB, mainly related to unconventional drilling in the United States.

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

	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
					(millions of barrels)						
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2019	3,204	529	166	604	3,357	105	7,965	1,404	4,185	466	14,020
Revisions	(677)	(66)	20	(25)	136	—	(612)	(305)	(213)	(27)	(1,157)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	20	—	—	—	—	—	20	12	—	—	32
Sales	(1)	—	(117)	—	—	—	(118)	(27)	—	—	(145)
Extensions/discoveries	710	125	—	—	—	—	835	263	—	—	1,098
Production	(168)	(31)	(30)	(132)	(158)	(11)	(530)	(72)	(114)	(24)	(740)
December 31, 2019	3,088	557	39	447	3,335	94	7,560	1,275	3,858	415	13,108
Attributable to noncontrolling interests		*21*						*3*	*894*	*126*	
Proportional interest in proved reserves of equity companies											
January 1, 2019	254	—	15	6	1,020	—	1,295	342	—	—	1,637
Revisions	15	—	—	—	(38)	—	(23)	3	—	—	(20)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	1	—	—	—	—	—	1	—	—	—	1
Production	(19)	—	(1)	—	(85)	—	(105)	(23)	—	—	(128)
December 31, 2019	251	—	14	6	897	—	1,168	322	—	—	1,490
Total liquids proved reserves at December 31, 2019	3,339	557	53	453	4,232	94	8,728	1,597	3,858	415	14,598
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2020	3,088	557	39	447	3,335	94	7,560	1,275	3,858	415	13,108
Revisions	(1,139)	(14)	(9)	19	(20)	(10)	(1,173)	(209)	(3,653)	(79)	(5,114)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	(1)	(2)	—	—	—	—	(3)	(3)	—	—	(6)
Extensions/discoveries	187	1	—	—	—	—	188	65	1	133	387
Production	(176)	(45)	(8)	(110)	(165)	(10)	(514)	(74)	(125)	(25)	(738)
December 31, 2020	1,959	497	22	356	3,150	74	6,058	1,054	81	444	7,637
Attributable to noncontrolling interests		*7*						*1*	*25*	*135*	
Proportional interest in proved reserves of equity											

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

	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2021	1,959	497	22	356	3,150	74	6,058	1,054	81	444	7,637
Revisions	47	(2)	15	67	36	10	173	4	2,944	17	3,138
Improved recovery	—	—	—	—	—	—	—	—	2	—	2
Purchases	5	—	—	—	—	—	5	1	—	—	6
Sales	(27)	(8)	(28)	—	—	—	(63)	(20)	—	—	(83)
Extensions/discoveries	499	329	—	—	—	—	828	183	—	—	1,011
Production	(176)	(47)	(6)	(88)	(149)	(10)	(476)	(86)	(133)	(23)	(718)
December 31, 2021	2,307	769	3	335	3,037	74	6,525	1,136	2,894	438	10,993
Attributable to noncontrolling interests		*9*						*1*	*674*	*133*	
Proportional interest in proved reserves of equity companies											
January 1, 2021	131	—	9	6	825		971	277	—	—	1,248
Revisions	38	—	2	(1)	(8)	—	31	15	—	—	46
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	2	—	—	—	—	—	2	—	—	—	2
Production	(16)	—	(1)	—	(76)	—	(93)	(22)	—	—	(115)
December 31, 2021	155	—	10	5	741	—	911	270	—	—	1,181
Total liquids proved reserves at December 31, 2021	2,462	769	13	340	3,778	74	7,436	1,406	2,894	438	12,174

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ Other Americas	Canada/ Other Americas	Total
					(millions of barrels)					
Proved developed reserves, as of December 31, 2019										
Consolidated subsidiaries	1,655	195	23	419	2,309	90	4,691	3,528	415	8,634
Equity companies	200	—	13	—	727	—	940	—	—	940
Proved undeveloped reserves, as of December 31, 2019										
Consolidated subsidiaries	2,474	381	29	68	1,157	35	4,144	330	—	4,474
Equity companies	60	—	1	6	483	—	550	—	—	550
Total liquids proved reserves at December 31, 2019	4,389	576	66	493	4,676	125	10,325	3,858	415	14,598
Proved developed reserves, as of December 31, 2020										
Consolidated subsidiaries	1,473	293	13	345	2,299	67	4,490	76	311	4,877
Equity companies	111	—	8	—	646	—	765	—	—	765
Proved undeveloped reserves, as of December 31, 2020										
Consolidated subsidiaries	1,342	209	16	42	975	38	2,622	5	133	2,760
Equity companies	24	—	1	6	452	—	483	—	—	483
Total liquids proved reserves at December 31, 2020	2,950	502	38	393	4,372	105	8,360	81	444	8,885
Proved developed reserves, as of December 31, 2021										
Consolidated subsidiaries	1,663	268	3	330	2,154	63	4,481	2,635	326	7,442
Equity companies	133	—	10	—	474	—	617	—	—	617
Proved undeveloped reserves, as of December 31, 2021										
Consolidated subsidiaries	1,621	508	—	31	988	32	3,180	259	112	3,551
Equity companies	28	—	—	5	531	—	564	—	—	564

(1) See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional information on natural gas liquids proved reserves see Item 2. Properties in ExxonMobil's 2021 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(1)***
				(billions of cubic feet)				*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2019	21,403	1,744	1,312	588	3,841	7,462	36,350	20,078
Revisions	(3,213)	(301)	41	(171)	953	39	(2,652)	(1,599)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	85	—	—	—	—	—	85	47
Sales	(297)	(29)	(416)	—	—	—	(742)	(269)
Extensions/discoveries	2,151	166	—	—	—	—	2,317	1,484
Production	(1,103)	(114)	(316)	(40)	(361)	(500)	(2,434)	(1,145)
December 31, 2019	19,026	1,466	621	377	4,433	7,001	32,924	18,596
Attributable to noncontrolling interests		*256*						
Proportional interest in proved reserves of equity companies								
January 1, 2019	225	—	1,057	863	13,321	—	15,466	4,215
Revisions	(1)	—	(238)	45	142	—	(52)	(29)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—
Extensions/discoveries	1	—	—	—	—	—	1	1
Production	(12)	—	(238)	—	(1,009)	—	(1,259)	(338)
December 31, 2019	213	—	581	908	12,454	—	14,156	3,849
Total proved reserves at December 31, 2019	19,239	1,466	1,202	1,285	16,887	7,001	47,080	22,445
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2020	19,026	1,466	621	377	4,433	7,001	32,924	18,596
Revisions	(4,904)	(753)	(4)	(23)	245	(405)	(5,844)	(6,088)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	(35)	(30)	—	—	—	—	(65)	(17)
Extensions/discoveries	433	1	1	—	—	—	435	459
Production	(1,081)	(123)	(177)	(34)	(369)	(462)	(2,246)	(1,113)
December 31, 2020	13,439	561	441	320	4,309	6,134	25,204	11,837
Attributable to noncontrolling interests		*84*						
Proportional interest in proved reserves of equity companies								
January 1, 2020	213	—	581	908	12,454	—	14,156	3,849
Revisions	(99)	—	(95)	9	(106)	—	(291)	(172)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(1)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2021	13,439	561	441	320	4,309	6,134	25,204	11,837
Revisions	1,432	305	210	39	(276)	712	2,422	3,542
Improved recovery	—	—	—	—	—	—	—	2
Purchases	3	—	—	—	—	—	3	6
Sales	(164)	(18)	(120)	—	—	—	(302)	(134)
Extensions/discoveries	1,381	163	—	—	—	—	1,544	1,269
Production	(1,103)	(92)	(148)	(42)	(340)	(483)	(2,208)	(1,086)
December 31, 2021	14,988	919	383	317	3,693	6,363	26,663	15,436
Attributable to noncontrolling interests		*124*						
Proportional interest in proved reserves of equity companies								
January 1, 2021	102	—	360	917	11,377	—	12,756	3,374
Revisions	44	—	206	(111)	(236)	—	(97)	30
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—
Extensions/discoveries	5	—	—	—	—	—	5	3
Production	(11)	—	(158)	—	(983)	—	(1,152)	(307)
December 31, 2021	140	—	408	806	10,158	—	11,512	3,100
Total proved reserves at December 31, 2021	15,128	919	791	1,123	13,851	6,363	38,175	18,536

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(1)***
				(billions of cubic feet)				*(millions of oil-equivalent barrels)*
Proved developed reserves, as of December 31, 2019								
Consolidated subsidiaries	11,882	613	502	377	3,508	3,765	20,647	12,075
Equity companies	143	—	505	—	9,859	—	10,507	2,691
Proved undeveloped reserves, as of December 31, 2019								
Consolidated subsidiaries	7,144	853	119	—	925	3,236	12,277	6,521
Equity companies	70	—	76	908	2,595	—	3,649	1,158
Total proved reserves at December 31, 2019	19,239	1,466	1,202	1,285	16,887	7,001	47,080	22,445
Proved developed reserves, as of December 31, 2020								
Consolidated subsidiaries	10,375	472	399	318	3,323	3,344	18,231	7,915
Equity companies	83	—	293	—	8,992	—	9,368	2,326
Proved undeveloped reserves, as of December 31, 2020								
Consolidated subsidiaries	3,064	89	42	2	986	2,790	6,973	3,922
Equity companies	19	—	67	917	2,385	—	3,388	1,048
Total proved reserves at December 31, 2020	13,541	561	801	1,237	15,686	6,134	37,960	15,211
Proved developed reserves, as of December 31, 2021								
Consolidated subsidiaries	11,287	574	377	315	2,527	3,513	18,593	10,540
Equity companies	117	—	339	—	6,017	—	6,473	1,696
Proved undeveloped reserves, as of December 31, 2021								
Consolidated subsidiaries	3,701	345	6	2	1,166	2,850	8,070	4,896
Equity companies	23	—	69	806	4,141	—	5,039	1,404
Total proved reserves at December 31, 2021	15,128	919	791	1,123	13,851	6,363	38,175	18,536

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

Standardized Measure of Discounted Future Cash Flows

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

Standardized Measure of Discounted Future Cash Flows	**United States**	**Canada/ Other Americas** *(1)*	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2019							
Future cash inflows from sales of oil and gas	208,981	190,604	5,789	30,194	215,837	43,599	695,004
Future production costs	90,448	133,606	3,209	10,177	58,255	12,980	308,675
Future development costs	53,641	31,158	4,397	6,756	14,113	8,109	118,174
Future income tax expenses	12,530	5,888	(594)	5,374	108,316	5,158	136,672
Future net cash flows	52,362	19,952	(1,223)	7,887	35,153	17,352	131,483
Effect of discounting net cash flows at 10%	30,499	7,728	(1,265)	872	18,658	7,491	63,983
Discounted future net cash flows	21,863	12,224	42	7,015	16,495	9,861	67,500
Equity Companies							
As of December 31, 2019							
Future cash inflows from sales of oil and gas	15,729	—	3,194	2,509	115,451	—	136,883
Future production costs	6,848	—	1,302	246	48,259	—	56,655
Future development costs	3,681	—	1,182	247	11,463	—	16,573
Future income tax expenses	—	—	346	555	17,891	—	18,792
Future net cash flows	5,200	—	364	1,461	37,838	—	44,863
Effect of discounting net cash flows at 10%	2,721	—	41	1,112	18,573	—	22,447
Discounted future net cash flows	2,479	—	323	349	19,265	—	22,416
Total consolidated and equity interests in standardized measure of discounted future net cash flows	24,342	12,224	365	7,364	35,760	9,861	89,916

(1) Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $1,064 million in 2019.

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ Other Americas *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
	(millions of dollars)						
Consolidated Subsidiaries							
As of December 31, 2020							
Future cash inflows from sales of oil and gas	93,520	38,193	2,734	15,411	138,080	19,794	307,732
Future production costs	53,635	19,971	1,815	6,527	42,378	3,188	127,514
Future development costs	27,668	10,991	4,244	6,223	13,432	7,580	70,138
Future income tax expenses	(2,509)	851	(1,121)	916	62,223	1,381	61,741
Future net cash flows	14,726	6,380	(2,204)	1,745	20,047	7,645	48,339
Effect of discounting net cash flows at 10%	8,564	1,116	(1,565)	(511)	10,557	3,624	21,785
Discounted future net cash flows	6,162	5,264	(639)	2,256	9,490	4,021	26,554
Equity Companies							
As of December 31, 2020							
Future cash inflows from sales of oil and gas	5,304	—	1,511	740	63,105	—	70,660
Future production costs	3,467	—	694	247	29,170	—	33,578
Future development costs	2,243	—	1,054	163	9,929	—	13,389
Future income tax expenses	—	—	(115)	42	8,088	—	8,015
Future net cash flows	(406)	—	(122)	288	15,918	—	15,678
Effect of discounting net cash flows at 10%	(378)	—	(86)	258	7,443	—	7,237
Discounted future net cash flows	(28)	—	(36)	30	8,475	—	8,441
Total consolidated and equity interests in standardized measure of discounted future net cash flows	6,134	5,264	(675)	2,286	17,965	4,021	34,995
Consolidated Subsidiaries							
As of December 31, 2021							
Future cash inflows from sales of oil and gas	217,023	209,711	4,322	24,812	211,255	69,015	736,138
Future production costs	63,464	111,468	1,142	7,700	55,241	14,880	253,895
Future development costs	29,941	31,736	2,113	5,921	14,519	7,286	91,516
Future income tax expenses	24,770	12,004	451	4,319	107,577	13,038	162,159
Future net cash flows	98,848	54,503	616	6,872	33,918	33,811	228,568
Effect of discounting net cash flows at 10%	50,524	25,793	(502)	739	17,383	18,751	112,688
Discounted future net cash flows	48,324	28,710	1,118	6,133	16,535	15,060	115,880
Equity Companies							
As of December 31, 2021							
Future cash inflows from sales of oil and gas	10,607	—	5,889	4,553	146,845	—	167,894
Future production costs	5,005	—	785	261	49,810	—	55,861
Future development costs	2,340	—	1,137	62	8,317	—	11,856

(1) Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $(150) million in 2020 and $3,666 million in 2021.

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

Consolidated and Equity Interests	2019		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2018	106,104	37,572	143,676
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/ sales less related costs	(1,252)	4	(1,248)
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(29,159)	(8,202)	(37,361)
Development costs incurred during the year	16,544	2,927	19,471
Net change in prices, lifting and development costs	(66,455)	(21,046)	(87,501)
Revisions of previous reserves estimates	4,906	657	5,563
Accretion of discount	11,433	3,956	15,389
Net change in income taxes	25,379	6,548	31,927
Total change in the standardized measure during the year	(38,604)	(15,156)	(53,760)
Discounted future net cash flows as			

Consolidated and Equity Interests	2020		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2019	67,500	22,416	89,916
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/sales less related costs	169	—	169
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(15,048)	(3,818)	(18,866)
Development costs incurred during the year	9,969	1,760	11,729
Net change in prices, lifting and development costs	(80,444)	(21,739)	(102,183)
Revisions of previous reserves estimates	2,614	680	3,294
Accretion of discount	10,786	3,011	13,797
Net change in income taxes	31,008	6,131	37,139
Total change in the standardized measure during the year	(40,946)	(13,975)	(54,921)
Discounted future net cash flows as of December 31	26,554	8,441	34,995

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

Consolidated and Equity Interests (continued)		**2021**	
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2020	26,554	8,441	34,995
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/sales less related costs	11,922	22	11,944
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(35,813)	(9,948)	(45,761)
Development costs incurred during the year	7,033	1,563	8,596
Net change in prices, lifting and development costs	118,946	47,434	166,380
Revisions of previous reserves estimates	27,126	2,507	29,633
Accretion of discount	3,762	1,201	4,963
Net change in income taxes	(43,650)	(13,281)	(56,931)
Total change in the standardized measure during the year	89,326	29,498	118,824
Discounted future net cash flows as of December 31, 2021	115,880	37,939	153,819

INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the Registrant’s Annual Report on Form 10-K for 2015).
3(ii)	By-Laws, as revised effective March 1, 2020 (incorporated by reference to Exhibit 3(ii) to the Registrant’s Report on Form 8-K of March 3, 2020).
4(vi)	Description of ExxonMobil Capital Stock (incorporated by reference to Exhibit 4(vi) to the Registrant's Annual Report on Form 10-K for 2019).
10(iii)(a.1)	2003 Incentive Program, as approved by shareholders May 28, 2003 (incorporated by reference to Exhibit 10(iii)(a.1) to the Registrant’s Annual Report on Form 10-K for 2017).*
10(iii)(a.2)	Extended Provisions for Restricted Stock Agreements (incorporated by reference to Exhibit 10(iii)(a.2) to the Registrant’s Annual Report on Form 10-K for 2016).*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements – Settlement in Shares.*
10(iii)(b.1)	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 10(iii)(b.1) to the Registrant’s Annual Report on Form 10-K for 2018).*
10(iii)(b.2)	Earnings Bonus Unit instrument (incorporated by reference to Exhibit 10(iii)(b.2) to the Registrant's Annual Report on Form 10-K for 2019).*
10(iii)(b.3)	2018 and 2019 Earnings Bonus Unit instruments, as revised effective November 23, 2021 (incorporated by reference to Exhibit 99.1 to the Registrant's Report on Form 8-K of November 30, 2021).*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2021).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2021).*
10(iii)(c.3)	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2021).*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Registrant’s Annual Report on Form 10-K for 2016).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f.1) to the Registrant’s Annual Report on Form 10-K for 2018).*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by reference to Exhibit 10(iii)(f.2) to the Registrant’s Annual Report on Form 10-K for 2016).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors.*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated March 1, 2020 (incorporated by reference to Exhibit 10(iii)(f.4) to the Registrant’s Report on Form 10-Q for the quarter ended March 31, 2020).*

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

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

SIGNATURES

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

EXXON MOBIL CORPORATION

By: /s/ DARREN W. WOODS

(Darren W. Woods,
Chairman of the Board)

Dated February 23, 2022

POWER OF ATTORNEY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated and on February 23, 2022.

/s/ DARREN W. WOODS	Chairman of the Board
(Darren W. Woods)	(Principal Executive Officer)
/s/ MICHAEL J. ANGELAKIS	Director
(Michael J. Angelakis)	
/s/ SUSAN K. AVERY	Director
(Susan K. Avery)	
/s/ ANGELA F. BRALY	Director
(Angela F. Braly)	
/s/ URSULA M. BURNS	Director
(Ursula M. Burns)	

/s/ KENNETH C. FRAZIER (Kenneth C. Frazier)	Director
/s/ GREGORY J. GOFF (Gregory J. Goff)	Director
/s/ KAISA H. HIETALA (Kaisa H. Hietala)	Director
/s/ JOSEPH L. HOOLEY (Joseph L. Hooley)	Director
/s/ STEVEN A. KANDARIAN (Steven A. Kandarian)	Director
/s/ ALEXANDER A. KARSNER (Alexander A. Karsner)	Director
/s/ JEFFREY W. UBBEN (Jeffrey W. Ubben)	Director
/s/ KATHRYN A. MIKELLS (Kathryn A. Mikells)	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ LEN M. FOX (Len M. Fox)	Vice President and Controller (Principal Accounting Officer)

2020

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, 2020

or

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

For the transition period from _______ to _______

Commission File Number 1-2256

Exxon Mobil Corporation

(Exact name of registrant as specified in its charter)

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

5959 Las Colinas Boulevard, Irving, Texas 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 940-6000

(Registrant's telephone number, including area code)

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

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, without par value	**XOM**	**New York Stock Exchange**
0.142% Notes due 2024	**XOM24B**	**New York Stock Exchange**
0.524% Notes due 2028	**XOM28**	**New York Stock Exchange**
0.835% Notes due 2032	**XOM32**	**New York Stock Exchange**
1.408% Notes due 2039	**XOM39A**	**New York Stock Exchange**

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

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

The aggregate market value of the voting stock held by non-affiliates of the registrant on June 30, 2020, the last business day of the registrant’s most recently completed second fiscal quarter, based on the closing price on that date of $44.72 on the New York Stock Exchange composite tape, was in excess of $189 billion.

Class	Outstanding as of January 31, 2021
Common stock, without par value	**4,233,483,160**

Documents Incorporated by Reference: Proxy Statement for the 2021 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2020

TABLE OF CONTENTS

PART I

PART II

PART III

PART IV

PART I

ITEM 1. BUSINESS

Exxon Mobil Corporation was incorporated in the State of New Jersey in 1882. Divisions and affiliated companies of ExxonMobil operate or market products in the United States and most other countries of the world. Their principal business 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, both within the industries and also with other industries in supplying the energy, fuel and chemical needs of 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: “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 9 thousand active patents worldwide at the end of 2020. For technology licensed to third parties, revenues totaled approximately $130 million in 2020. 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.

ExxonMobil operates in a highly complex, competitive and changing global energy business environment where decisions and risks play out over time horizons that are often decades in length. This long-term orientation underpins the Corporation's philosophy on talent development.

Talent development begins with recruiting exceptional candidates and continues with individually planned experiences and training designed to facilitate broad development and a deep understanding of our business across the business cycle. Our career-oriented approach to talent development results in strong retention and an average length of service of 30 years for our career employees. Compensation, benefits and workplace programs support the Corporation's talent management approach, and are designed to attract and retain employees for a career through compensation that is market competitive, long-term oriented, and highly differentiated by individual performance.

Sixty percent of our global employee workforce is from outside the U.S., and over the past decade 39 percent of our global hires for management, professional and technical positions were female and 31 percent of our U.S. hires for management, professional and technical positions were minorities. With over 160 nationalities represented in the Company, we encourage and respect diversity of thought, ideas and perspective from our workforce. We consider and monitor diversity through all stages of employment, including recruitment, training and development of our employees. We also work closely with the communities where we operate to identify and invest in initiatives that help support local needs, including local talent and skill development.

The number of regular employees was 72 thousand, 75 thousand, and 71 thousand at years ended 2020, 2019, and 2018, 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.

As discussed in item 1A. Risk Factors in this report, compliance with existing and potential future government regulations, including taxes, environmental regulations, and other government regulations and policies that directly or indirectly affect the production and sale of our products, may have material effects on the capital expenditures, earnings, and competitive position of ExxonMobil. With respect to the environment, throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground, including, but not limited to, compliance with environmental regulations. 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 2020 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.5 billion, of which $3.4 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $4.9 billion in 2021 and 2022. Capital expenditures are expected to account for approximately 25 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. 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, Code of Ethics and Business Conduct, and additional policies as well as the charters of the audit, compensation, and other 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, trade tariffs, security or public health issues and responses, 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. Demand reduction due to the COVID-19 pandemic as well as accompanying conditions of oversupply have led to a significant decrease in commodity prices and margins. Future business results, including cash flows and financing needs, will be affected by the extent and duration of these conditions and the effectiveness of responsive actions that the Corporation and others take, including actions to reduce capital and operating expenses, and actions taken by governments and others to address the COVID-19 pandemic including the ongoing development and distribution of COVID-19 vaccines, and the impact of the pandemic on national and global economies and markets.

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, or government policy support for, alternative energy sources; changes in technology that alter fuel choices, such as technological advances in energy storage that make wind and solar more competitive for power generation; changes in consumer preferences for our products, including consumer demand for alternative fueled or electric transportation or alternatives to plastic products; 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, government policies that restrict oil and gas production or increase associated costs, 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, including by restricting leasing or permitting activities, or may place resources off-limits from development altogether. Restrictions on production of oil and gas could increase to the extent governments view such measures as a viable approach for pursuing national and global energy and climate policies. 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 affecting offshore drilling operations, water use, methane emissions, hydraulic fracturing or use of plastics);
- actions by regulators or other political actors to delay or deny necessary licenses and permits or restrict the transportation of our products;
- 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; by government enforcement proceedings alleging non-compliance with applicable laws or regulations; or by state and local government actors as well as private plaintiffs acting in parallel that attempt to use the legal system to promote public policy agendas, gain political notoriety, or obtain monetary awards from the Company.

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. Driven by 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 or production and use of oil and gas. These include adoption of cap and trade regimes, carbon taxes, trade tariffs, minimum renewable usage requirements, restrictive permitting, increased efficiency standards, and incentives or mandates for renewable energy. Political and other actors and their agents also increasingly seek to advance climate change objectives indirectly, such as by seeking to reduce the availability of or increase the cost for, financing and investment in the oil and gas sector and taking actions intended to promote changes in business strategy for oil and gas companies. Depending on how policies are formulated and applied, they could have the potential to negatively affect investment returns, make our products more expensive or 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.

Alternative energy. Many governments are providing tax advantages and other subsidies to support transitioning to 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 in the U.S., and in Singapore with Nanyang Technological Institute and the National University. Our research projects focus on developing advanced biofuels and hydrogen, carbon capture and storage, breakthrough energy efficiency processes, advanced energy-saving materials, and other technologies in collaboration with our partners including Synthetic Genomics, FuelCell Energy and Global Thermostat. 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 and strategies to divest assets. We may not be able to divest assets at a price or on the timeline we contemplate in our strategies. Additionally, we may retain certain liabilities following a divestment and could be held liable for past use or for different liabilities than anticipated.

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, including successfully applying advances in the ability to process very large amounts of data to our businesses.

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 or if our proprietary data is otherwise not protected, 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 and as partners with other private firms. 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, change in consumer views concerning our products, 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, obtain financing, 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 2020

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. Primarily as a result of very low prices during 2020 and the effects of reductions in capital expenditures, under the SEC definition of proved reserves, certain quantities of crude oil, bitumen, and natural gas that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2020. Otherwise, no major discovery or other favorable or adverse event has occurred since December 31, 2020, that would cause a significant change in the estimated proved reserves as of that date.

	Crude Oil	Natural Gas Liquids	Bitumen	Synthetic Oil	Natural Gas	Oil-Equivalent Total All Products
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million bbls)*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,029	444	—	—	10,375	3,202
Canada/Other Americas *(1)*	288	5	76	311	472	759
Europe	11	2	—	—	399	79
Africa	314	31	—	—	318	398
Asia	2,215	84	—	—	3,323	2,853
Australia/Oceania	44	23	—	—	3,344	624
Total Consolidated	3,901	589	76	311	18,231	7,915
Equity Companies						
United States	107	4	—	—	83	125
Europe	8	—	—	—	293	57
Africa	—	—	—	—	—	—
Asia	432	214	—	—	8,992	2,144
Total Equity Company	547	218	—	—	9,368	2,326
Total Developed	4,448	807	76	311	27,599	10,241
Undeveloped						
Consolidated Subsidiaries						
United States	930	412	—	—	3,064	1,853
Canada/Other Americas *(1)*	209	—	5	133	89	362
Europe	11	5	—	—	42	23
Africa	42	—	—	—	2	42
Asia	935	40	—	—	986	1,139
Australia/Oceania	30	8	—	—	2,790	503
Total Consolidated	2,157	465	5	133	6,973	3,922
Equity Companies						
United States	24	—	—	—	19	27
Europe	1	—	—	—	67	12
Africa	6	—	—	—	917	159
Asia	393	59	—	—	2,385	850
Total Equity Company	424	59	—	—	3,388	1,048
Total Undeveloped	2,581	524	5	133	10,361	4,970
Total Proved Reserves	7,029	1,331	81	444	37,960	15,211

(1) Other Americas includes proved developed reserves of 119 million barrels of crude oil and 138 billion cubic feet of natural gas, as well as proved undeveloped reserves of 179 million barrels of crude oil and 77 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 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 crude 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.

During the first and second quarters of 2020, the balance of supply and demand for petroleum and petrochemical products experienced two significant disruptive effects. On the demand side, the COVID-19 pandemic spread rapidly through most areas of the world resulting in substantial reductions in consumer and business activity and significantly reduced demand for crude oil, natural gas, and petroleum products. This reduction in demand coincided with announcements of increased production in certain key oil-producing countries which led to increases in inventory levels and sharp declines in prices for crude oil, natural gas, and petroleum products. Market conditions continued to reflect considerable uncertainty throughout 2020.

As noted above, certain quantities of crude oil, bitumen, and natural gas that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2020. Amounts no longer qualifying as proved reserves include 3.1 billion barrels of bitumen at Kearl, 0.6 billion barrels of bitumen at Cold Lake, and 0.5 billion oil-equivalent barrels in the United States. The Corporation's near-term reduction in capital expenditures resulted in a net reduction to estimates of proved reserves of approximately 1.5 billion oil-equivalent barrels, mainly related to unconventional drilling in the United States. Among the factors that could result in portions of these amounts being recognized again as proved reserves at some point in the future are a recovery in the SEC price basis, cost reductions, operating efficiencies, and increases in planned capital spending.

B. Technologies Used in Establishing Proved Reserves Additions in 2020

Additions to ExxonMobil's proved reserves in 2020 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 and Resources 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 and Resources group has more than 30 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 15 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves under SEC guidelines. This group includes individuals who hold degrees in either Engineering or Geology.

The Global Reserves and Resources 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, commercial and market assessments, analysis of well and field performance, and long-standing approval guidelines. 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 geoscience and engineering professionals within the operating organization. In addition, changes to reserves estimates that exceed certain thresholds require further review and approval by the appropriate level of management within the operating organization before the changes may be made in the central database. Endorsement by the Global Reserves and Resources 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 2020, approximately 5.0 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 33 percent of the 15.2 GOEB reported in proved reserves. This compares to the 7.7 GOEB of proved undeveloped reserves reported at the end of 2019. During the year, ExxonMobil conducted development activities that resulted in the transfer of approximately 0.9 GOEB from proved undeveloped to proved developed reserves by year end. The largest transfers were related to development activities in the United States, Qatar, the United Arab Emirates, and Guyana. During 2020, extensions, primarily in the United States and Canada, resulted in an addition of approximately 0.5 GOEB of proved undeveloped reserves. Also, as a result of very low prices during 2020 and the effects of reductions in capital expenditures, the Corporation reclassified approximately 2.3 GOEB of proved undeveloped reserves which no longer met the SEC definition of proved reserves, primarily in the United States and Canada.

Overall, investments of $10.7 billion were made by the Corporation during 2020 to progress the development of reported proved undeveloped reserves, including $10.4 billion for oil and gas producing activities, along with additional investments for other non-oil and gas producing activities such as the construction of support infrastructure and other related facilities. These investments represented 74 percent of the $14.4 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 Australia, Kazakhstan, the United States, and the United Arab Emirates 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 crude 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 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 Tengizchevroil joint venture development that includes a production license in the Tengiz - Korolev field complex. The Tengizchevroil joint venture is producing, and proved undeveloped reserves will continue to move to proved developed as approved development phases progress. In the United Arab Emirates, proved undeveloped reserves are associated with an approved development plan and continued drilling investment for the producing Upper Zakum field.

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.

	2020		2019		2018	
	(thousands of barrels daily)					
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries						
United States	481	154	461	131	395	101
Canada/Other Americas *(1)*	121	5	87	4	62	6
Europe	22	5	84	21	101	27
Africa	301	11	360	12	377	10
Asia	449	23	432	22	398	25
Australia/Oceania	29	15	30	15	31	16
Total Consolidated Subsidiaries	1,403	213	1,454	205	1,364	185
Equity Companies						
United States	49	1	52	2	54	1
Europe	3	—	3	—	4	—
Asia	208	62	232	62	226	62
Total Equity Companies	260	63	287	64	284	63
Total crude oil and natural gas liquids production	1,663	276	1,741	269	1,648	248
Bitumen production						
Consolidated Subsidiaries						
Canada/Other Americas	342		311		310	
Synthetic oil production						
Consolidated Subsidiaries						
Canada/Other Americas	68		65		60	
Total liquids production	2,349		2,386		2,266	
	(millions of cubic feet daily)					
Natural gas production available for sale						
Consolidated Subsidiaries						
United States	2,668		2,756		2,550	
Canada/Other Americas *(1)*	277		258		227	
Europe	447		808		925	
Africa	9		7		13	
Asia	872		851		838	
Australia/Oceania	1,219		1,319		1,325	
Total Consolidated Subsidiaries	5,492		5,999		5,878	
Equity Companies						
United States	23		22		24	
Europe	342		649		728	
Asia	2,614		2,724		2,775	
Total Equity Companies	2,979		3,395		3,527	
Total natural gas production available for sale	8,471		9,394		9,405	
	(thousands of oil-equivalent barrels daily)					
Oil-equivalent production	3,761		3,952		3,833	

(1) Other Americas includes crude oil production for 2020, 2019 and 2018 of 29 thousand, 2 thousand, and 2 thousand barrels daily, respectively; and natural gas production available for sale for 2020, 2019 and 2018 of 45 million, 36 million, and 28 million cubic feet daily, respectively.

B. Production Prices and Production Costs

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

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2020				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	34.97	37.26	41.39	42.27	39.39	36.67	38.31
NGL, per barrel	13.83	10.34	20.11	21.32	21.37	27.92	16.05
Natural gas, per thousand cubic feet	0.98	1.56	3.13	1.24	1.49	4.34	2.01
Bitumen, per barrel	—	17.71	—	—	—	—	17.71
Synthetic oil, per barrel	—	37.32	—	—	—	—	37.32
Average production costs, per oil-equivalent barrel - total	9.82	18.40	21.22	16.67	6.50	5.35	11.57
Average production costs, per barrel - bitumen	—	19.22	—	—	—	—	19.22
Average production costs, per barrel - synthetic oil	—	33.61	—	—	—	—	33.61
Equity Companies							
Average production prices							
Crude oil, per barrel	39.10	—	38.95	—	35.18	—	35.97
NGL, per barrel	11.05	—	—	—	30.02	—	29.58
Natural gas, per thousand cubic feet	1.19	—	3.85	—	3.14	—	3.20
Average production costs, per oil-equivalent barrel - total	27.39	—	30.74	—	1.63	—	5.49
Total							
Average production prices							
Crude oil, per barrel	35.35	37.26	41.11	42.27	38.07	36.67	37.95
NGL, per barrel	13.80	10.34	20.11	21.32	27.65	27.92	19.16
Natural gas, per thousand cubic feet	0.98	1.56	3.44	1.24	2.72	4.34	2.43
Bitumen, per barrel	—	17.71	—	—	—	—	17.71
Synthetic oil, per barrel	—	37.32	—	—	—	—	37.32
Average production costs, per oil-equivalent barrel - total	10.66	18.40	24.76	16.73	3.91	5.35	10.24
Average production costs, per barrel - bitumen	—	19.22	—	—	—	—	19.22
Average production costs, per barrel - synthetic oil	—	33.61	—	—	—	—	33.61
During 2019							
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	54.41	59.39	63.59	65.64	64.14	61.08	61.04
NGL, per barrel	18.94	16.59	30.56	41.41	24.64	30.55	22.85
Natural gas, per thousand cubic feet	1.54	1.44	4.50	1.49	2.07	6.26	3.05
Bitumen, per barrel	—	36.25	—	—	—	—	36.25
Synthetic oil, per barrel	—	56.18	—	—	—	—	56.18
Average production costs, per oil-equivalent barrel - total	12.25	23.41	13.69	17.51	7.34	6.60	13.43
Average production costs, per barrel - bitumen	—	24.18	—	—	—	—	24.18
Average production costs, per barrel - synthetic oil	—	40.38	—	—	—	—	40.38
Equity Companies							

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2018			*(dollars per unit)*				
Consolidated Subsidiaries							
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
Equity Companies							
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
Total							
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

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

	2020	2019	2018
Net Productive Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	4	3	1
Canada/Other Americas	2	6	4
Europe	—	1	—
Africa	1	—	1
Asia	—	—	—
Australia/Oceania	—	1	1
Total Consolidated Subsidiaries	7	11	7
Equity Companies			
United States	—	—	—
Europe	—	—	—
Africa	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total productive exploratory wells drilled	7	11	7
Net Dry Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	—	—	3
Canada/Other Americas	1	1	—
Europe	—	1	1
Africa	—	—	—
Asia	1	—	—
Australia/Oceania	—	1	2
Total Consolidated Subsidiaries	2	3	6
Equity Companies			
United States	—	—	—
Europe	—	—	—
Africa	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total dry exploratory wells drilled	2	3	6

	2020	2019	2018
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
United States	412	618	389
Canada/Other Americas	36	49	32
Europe	2	3	3
Africa	2	4	1
Asia	15	12	14
Australia/Oceania	4	—	—
Total Consolidated Subsidiaries	471	686	439
Equity Companies			
United States	60	199	168
Europe	1	—	3
Africa	—	—	—
Asia	5	9	6
Total Equity Companies	66	208	177
Total productive development wells drilled	537	894	616
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	6	8	4
Canada/Other Americas	—	—	1
Europe	—	—	—
Africa	—	1	1
Asia	—	—	—
Australia/Oceania	1	—	—
Total Consolidated Subsidiaries	7	9	6
Equity Companies			
United States	—	—	—
Europe	—	—	—
Africa	—	—	—
Asia	—	—	—
Total Equity Companies	—	—	—
Total dry development wells drilled	7	9	6
Total number of net wells drilled	553	917	635

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 2020, the company's share of net production of synthetic crude oil was about 68 thousand barrels per day and share of net acreage was about 55 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 2020, average net production at Kearl was about 219 thousand barrels per day.

Primarily as a result of very low prices during 2020, under the SEC definition of proved reserves, the entire 3.1 billion barrels of bitumen at Kearl did not qualify as proved reserves at year-end 2020. Among the factors that could result in portions of these amounts being recognized again as proved reserves at some point in the future are a recovery in the SEC price basis, cost reductions, and/or operating efficiencies.

5. Present Activities

A. Wells Drilling

	Year-End 2020		Year-End 2019	
	Gross	Net	Gross	Net
Wells Drilling				
Consolidated Subsidiaries				
United States	1,206	741	1,133	704
Canada/Other Americas	38	29	27	20
Europe	13	6	16	7
Africa	14	3	4	1
Asia	14	4	46	14
Australia/Oceania	—	—	14	4
Total Consolidated Subsidiaries	1,285	783	1,240	750
Equity Companies				
United States	3	1	3	1
Europe	1	1	—	—
Africa	6	1	6	1
Asia	2	1	11	3
Total Equity Companies	12	4	20	5
Total gross and net wells drilling	1,297	787	1,260	755

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2020 acreage holdings totaled 11.2 million net acres, of which 0.4 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska. Development activities continued on the Golden Pass liquefied natural gas export project.

During the year, 478.9 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.

ExxonMobil's net acreage in the Gulf of Mexico at year-end 2020 was 0.3 million acres. A total of 0.9 net development wells were completed during the year.

Participation in Alaska production and development continued with a total of 2.7 net development wells completed.

CANADA / OTHER AMERICAS

Canada

Oil and Gas Operations: ExxonMobil's year-end 2020 acreage holdings totaled 7.4 million net acres, of which 4.6 million net acres were offshore. A total of 6.1 net exploration and development wells were completed during the year.

In Situ Bitumen Operations: ExxonMobil's year-end 2020 in situ bitumen acreage holdings totaled 0.6 million net onshore acres. A total of 28 net development wells at Cold Lake were completed during the year.

Argentina

ExxonMobil's net acreage totaled 2.9 million acres, of which 2.6 million net acres were offshore at year-end 2020. During the year, a total of 1.8 net development wells were completed.

Guyana

ExxonMobil's net acreage totaled 4.6 million offshore acres at year-end 2020. During the year, 2.4 net exploration and development wells were completed. Development activities continued on the Liza Phase 2 project, and the Payara project was funded in 2020.

EUROPE

Germany

ExxonMobil's net acreage totaled 1.7 million onshore acres at year-end 2020. During the year, 0.8 net exploration and development wells were completed.

Netherlands

ExxonMobil's net interest in licenses totaled approximately 1.4 million acres, of which 1.0 million acres were onshore at year-end 2020. During the year, a total of 1.3 net exploration and development wells were completed. In 2020, the Dutch Government further reduced Groningen gas extraction and maintained its plan to terminate Groningen production in 2022.

United Kingdom

ExxonMobil's net interest in licenses totaled approximately 0.3 million offshore acres at year-end 2020. During the year, a total of 1.9 net development wells were completed. Development activities continued on the Penguins Redevelopment project.

AFRICA

Angola

ExxonMobil’s net acreage totaled approximately 3.0 million acres, of which 2.9 million net acres were offshore at year-end 2020. During the year, a total of 0.3 net development wells were completed. In 2020, ExxonMobil acquired approximately 2.7 million net acres in three offshore blocks located in the Namibe basin.

Chad

ExxonMobil’s net acreage holdings totaled 46 thousand onshore acres at year-end 2020.

Equatorial Guinea

ExxonMobil’s net acreage totaled 0.5 million offshore acres at year-end 2020. During the year, a total of 0.8 net development well was completed.

Mozambique

ExxonMobil’s net acreage totaled approximately 1.8 million offshore acres at year-end 2020. Development activities continued on the Coral South Floating LNG project during the year.

Nigeria

ExxonMobil’s net acreage totaled 0.9 million offshore acres at year-end 2020. During the year, a total of 1.8 net exploration and development wells were completed.

ASIA

Azerbaijan

ExxonMobil's net acreage totaled 7 thousand offshore acres at year-end 2020. During the year, a total of 0.7 net development wells were completed.

Indonesia

ExxonMobil’s net acreage totaled 0.1 million onshore acres at year-end 2020.

Iraq

ExxonMobil’s net acreage totaled 0.1 million onshore acres at year-end 2020. During the year, a total of 8.2 net development wells were completed at the West Qurna Phase I oil field. Oil field rehabilitation activities continued during 2020 and across the life of this project will include drilling of new wells, working over of existing wells, and optimization, debottlenecking and expansion of facilities. In the Kurdistan Region of Iraq, ExxonMobil has continued exploration activities.

Kazakhstan

ExxonMobil’s net acreage totaled 0.3 million acres, of which 0.2 million net acres were offshore at year-end 2020. During the year, a total of 4.5 net development wells were completed. Development activities continued on the Tengiz Expansion project.

Malaysia

ExxonMobil’s interests in production sharing contracts covered 0.2 million net acres offshore at year-end 2020. During the year, a total of 2.0 net development wells were completed. In 2020, ExxonMobil relinquished approximately 2.3 million net acres in three Sabah offshore blocks.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil’s net acreage totaled 65 thousand acres offshore at year-end 2020. ExxonMobil participated in 62.2 million tonnes per year gross liquefied natural gas capacity and 3.4

billion cubic feet per day of flowing gas capacity at year-end. During the year, a total of 0.3 net development well was completed. The Barzan project started up in 2020.

Russia

ExxonMobil's net acreage holdings in Sakhalin totaled 85 thousand offshore acres at year-end 2020. During the year, a total of 2.7 net exploration and development wells were completed.

Thailand

ExxonMobil's net onshore acreage in Thailand concessions totaled 16 thousand acres at year-end 2020. During the year, a total of 0.5 net exploration and development wells were completed.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2020. During the year, a total of 1.7 net development wells were completed. The Upper Zakum 750 project started up in 2020 while commissioning continued on the final systems. Development activities continued on the Upper Zakum 1 MBD project.

AUSTRALIA / OCEANIA

Australia

ExxonMobil's net acreage totaled 1.8 million acres offshore and 10 thousand acres onshore at year-end 2020. During the year, a total of 3.8 net development wells were completed. Development activities continued on the West Barracouta project during the year.

The co-venturer-operated Gorgon Jansz liquefied natural gas (LNG) development consists of a subsea infrastructure for offshore production and transportation of the gas, a 15.6 million tonnes per year LNG facility and a 280 million cubic feet per day domestic gas plant located on Barrow Island, Western Australia. Development activities continued on the Gorgon Stage 2 project during the year.

Papua New Guinea

ExxonMobil's net acreage totaled 5.5 million acres, of which 3.3 million net acres were offshore at year-end 2020. During the year, a total of 0.8 net exploration and development wells were completed. In 2020, ExxonMobil relinquished approximately 1.4 million net onshore acres. 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.

WORLDWIDE EXPLORATION

At year-end 2020, 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 29.8 million net acres were held at year-end 2020 and 0.7 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 31 million barrels of oil and 2,600 billion cubic feet of natural gas for the period from 2021 through 2023. 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 purchases on the open market as necessary.

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

A. Gross and Net Productive Wells

	Year-End 2020				Year-End 2019			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	19,631	7,878	20,480	12,195	20,559	8,502	21,893	13,182
Canada/Other Americas	4,754	4,644	3,276	1,275	4,905	4,724	3,441	1,347
Europe	559	126	487	221	741	207	517	236
Africa	1,141	432	26	10	1,191	456	13	5
Asia	974	310	132	78	943	301	133	79
Australia/Oceania	540	102	90	38	582	120	87	36
Total Consolidated Subsidiaries	27,599	13,492	24,491	13,817	28,921	14,310	26,084	14,885
Equity Companies								
United States	12,368	4,851	4,223	417	12,947	5,328	4,500	577
Europe	57	20	552	172	57	20	561	175
Asia	217	54	157	32	194	49	126	30
Total Equity Companies	12,642	4,925	4,932	621	13,198	5,397	5,187	782
Total gross and net productive wells	40,241	18,417	29,423	14,438	42,119	19,707	31,271	15,667

There were 25,595 gross and 22,239 net operated wells at year-end 2020 and 27,532 gross and 23,857 net operated wells at year-end 2019. The number of wells with multiple completions was 1,067 gross in 2020 and 1,023 gross in 2019.

B. Gross and Net Developed Acreage

	Year-End 2020		Year-End 2019	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	12,834	7,971	13,283	8,097
Canada/ Other Americas *(1)*	2,944	2,071	3,020	2,100
Europe	2,231	1,189	2,229	1,182
Africa	2,409	818	2,409	832
Asia	1,938	561	1,938	561
Australia/ Oceania	3,262	1,068	3,262	1,068
Total Consolidated Subsidiaries	25,618	13,678	26,141	13,840
Equity Companies				
United States	928	208	926	207
Europe	3,667	1,118	4,069	1,280
Asia	701	160	628	155
Total Equity Companies	5,296	1,486	5,623	1,642
Total gross and net developed acreage	30,914	15,164	31,764	15,482

(1) *Includes developed acreage in Other Americas of 490 gross and 311 net thousands of acres for 2020 and 472 gross and 295 net thousands of acres for 2019.*

Separate acreage data for oil and gas are not maintained because, in many instances, both are produced from the same acreage.

C. Gross and Net Undeveloped Acreage

	Year-End 2020		Year-End 2019	
	Gross	**Net**	**Gross**	**Net**
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	6,969	2,967	7,123	3,146
Canada/ Other Americas *(1)*	37,833	18,985	36,509	17,950
Europe	14,802	6,018	18,212	7,619
Africa	35,956	24,558	56,049	32,449
Asia	888	280	6,880	2,911
Australia/ Oceania	12,971	6,265	14,773	7,689
Total Consolidated Subsidiaries	109,419	59,073	139,546	71,764
Equity Companies				
United States	160	64	189	73
Europe	765	214	366	105
Africa	596	149	596	149
Asia	—	—	73	5
Total Equity Companies	1,521	427	1,224	332
Total gross and net undeveloped acreage	110,940	59,500	140,770	72,096

(1) *Includes undeveloped acreage in Other Americas of 26,084 gross and 12,471 net thousands of acres for 2020 and 25,327 gross and 12,065 net thousands of acres for 2019.*

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 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 2014. Pursuant to the amended law, the production term for an onshore unconventional concession is 35 years, and 25 years for a conventional concession, with unlimited 10-year extensions possible, once a field has been developed. In 2019, the government granted three offshore exploration licenses, with terms of eight years, divided into two exploration periods of four years, with an optional extension of five years for each license. Two onshore exploration concessions were initially granted prior to the amendment and are governed under Provincial Law with expiration terms through 2024.

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 and 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 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 subject to 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.

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 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 either production sharing agreements or other contracts with initial exploration terms ranging from three to four years with options to extend from one to five years. The production periods range from 20 to 30 years, and the agreements generally provide for negotiated extensions.

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 an approved plan of development becomes effective 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 2026. 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 10-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 10-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 to 20 percent of the contract area after three years and generally allow the contractor to retain no more than 50 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 10-year extensions.

Malaysia

Production activities are governed by production sharing contracts (PSCs) negotiated with the national oil company. The PSCs have production terms of 25 years. Extensions are generally subject to the national oil company's prior written approval.

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 between the Russian government and the Sakhalin-1 consortium, of which ExxonMobil is the operator.

Thailand

The Petroleum Act of 1971 allows production under ExxonMobil's concessions for 30 years with a 10-year extension at terms generally prevalent at the time. The term of one of the two concessions expires in 2021.

United Arab Emirates

An interest in the development and production activities of the offshore Upper Zakum 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 2020 *(1)*

		ExxonMobil Share KBD *(2)*	ExxonMobil Interest %
United States			
Joliet	Illinois	254	100
Baton Rouge	Louisiana	520	100
Billings	Montana	60	100
Baytown	Texas	561	100
Beaumont	Texas	369	100
Total United States		1,764	
Canada			
Strathcona	Alberta	196	69.6
Nanticoke	Ontario	113	69.6
Sarnia	Ontario	119	69.6
Total Canada		428	
Europe			
Antwerp	Belgium	307	100
Fos-sur-Mer	France	133	82.9
Gravenchon	France	244	82.9
Karlsruhe	Germany	78	25
Trecate	Italy	132	75.2
Rotterdam	Netherlands	192	100
Slagen	Norway	116	100
Fawley	United Kingdom	262	100
Total Europe		1,464	
Asia Pacific			
Altona *(3)*	Australia	88	100
Fujian	China	67	25
Jurong/PAC	Singapore	592	100
Sriracha	Thailand	167	66
Total Asia Pacific		914	
Middle East			
Yanbu	Saudi Arabia	200	50
Total Worldwide		4,770	

(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.

(3) The Corporation expects to convert the Altona refinery into a terminal in 2021.

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

Retail Sites At Year-End 2020

United States	
Owned/leased	—
Distributors/resellers	10,982
Total United States	10,982
Canada	
Owned/leased	—
Distributors/resellers	2,370
Total Canada	2,370
Europe	
Owned/leased	197
Distributors/resellers	5,764
Total Europe	5,961
Asia Pacific	
Owned/leased	569
Distributors/resellers	1,243
Total Asia Pacific	1,812
Latin America	
Owned/leased	—
Distributors/resellers	411
Total Latin America	411
Middle East/Africa	
Owned/leased	225
Distributors/resellers	192
Total Middle East/Africa	417
Worldwide	
Owned/leased	991
Distributors/resellers	20,962
Total Worldwide	21,953

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 2020 *(1)*

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest %
		(millions of metric tons per year)				
North America						
Baton Rouge	Louisiana	1.1	1.3	0.4	—	100
Baytown	Texas	3.9	—	0.7	0.6	100
Beaumont	Texas	0.9	1.7	—	0.3	100
Mont Belvieu	Texas	—	2.3	—	—	100
Sarnia	Ontario	0.3	0.5	—	—	69.6
Total North America		6.2	5.8	1.1	0.9	
Europe						
Antwerp	Belgium	—	0.4	—	—	100
Fife	United Kingdom	0.4	—	—	—	50
Gravenchon	France	0.4	0.4	0.3	—	100
Meerhout	Belgium	—	0.5	—	—	100
Rotterdam	Netherlands	—	—	—	0.7	100
Total Europe		0.8	1.3	0.3	0.7	
Middle East						
Al Jubail	Saudi Arabia	0.6	0.7	—	—	50
Yanbu	Saudi Arabia	1.0	0.7	0.2	—	50
Total Middle East		1.6	1.4	0.2	—	
Asia Pacific						
Fujian	China	0.3	0.2	0.2	0.2	25
Singapore	Singapore	1.9	1.9	0.9	1.8	100
Sriracha	Thailand	—	—	—	0.5	66
Total Asia Pacific		2.2	2.1	1.1	2.5	
Total Worldwide		10.8	10.6	2.7	4.1	

(1) 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

ExxonMobil has elected to use a $1 million threshold for disclosing environmental proceedings.

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.

Information about our Executive Officers

(positions and ages as of February 24, 2021)

Darren W. Woods	*Chairman of the Board*	
Held current title since:	January 1, 2017	Age: 56

Mr. Darren W. Woods became a Director and President of Exxon Mobil Corporation on January 1, 2016, and Chairman of the Board and Chief Executive Officer of Exxon Mobil Corporation on January 1, 2017, positions he continues to hold as of this filing date.

Neil A. Chapman	*Senior Vice President*	
Held current title since:	January 1, 2018	Age: 58

Mr. Neil A. Chapman 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.

Andrew P. Swiger	*Senior Vice President*	
Held current title since:	April 1, 2009	Age: 64

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.

Jack P. Williams, Jr.	*Senior Vice President*	
Held current title since:	June 1, 2014	Age: 57

Mr. Jack P. Williams, Jr. became Senior Vice President of Exxon Mobil Corporation on June 1, 2014, a position he continues to hold as of this filing date.

Ian S. Carr	*Vice President*	
Held current title since:	September 1, 2020	Age: 57

Mr. Ian S. Carr was Vice President, Strategy and Planning, ExxonMobil Refining & Supply Company May 1, 2014 – July 31, 2017. He was Vice President, Upstream Strategy and Planning, ExxonMobil Gas & Power Marketing Company August 1, 2017 – March 31, 2019. He was Vice President, Strategy and Portfolio Management, ExxonMobil Upstream Business Development Company April 1, 2019 - September 30, 2019. He was Senior Vice President, Fuels, ExxonMobil Fuels & Lubricants Company October 1, 2019 – August 31, 2020. He became President of ExxonMobil Fuels & Lubricants Company and Vice President of Exxon Mobil Corporation on September 1, 2020, positions he continues to hold as of this filing date.

Linda D. DuCharme	*Vice President* *President, ExxonMobil Integrated Solutions Company*	
Held current title since:	July 1, 2020, and April 1, 2019, respectively	Age: 56

Ms. Linda D. DuCharme was Vice President, Americas, Africa and Asia, ExxonMobil Gas & Power Marketing Company July 1, 2015 – July 31, 2016. She was President of ExxonMobil Global Services Company August 1, 2016 – March 31, 2019. She became President of ExxonMobil Upstream Integrated Solutions Company April 1, 2019, and President of ExxonMobil Upstream Business Development Company and Vice President of Exxon Mobil Corporation on July 1, 2020, positions she continues to hold as of this filing date.

Neil W. Duffin	*President, ExxonMobil Global Projects Company*	
Held current title since:	April 1, 2019	Age: 64

Mr. Neil W. Duffin was President of ExxonMobil Development Company April 13, 2007 – December 31, 2016. He

Stephen A. Littleton	*Vice President – Investor Relations and Secretary*	
Held current title since:	March 15, 2020	Age: 55

Mr. Stephen A. Littleton was Assistant Controller of Exxon Mobil Corporation June 1, 2015 - April 30, 2018. He was Vice President, Downstream Business Services and Downstream Controller May 1, 2018 - March 14, 2020. He became Vice President – Investor Relations and Secretary of Exxon Mobil Corporation on March 15, 2020, positions he continues to hold as of this filing date.

Liam M. Mallon	*Vice President*	
Held current title since:	April 1, 2019	Age: 58

Mr. Liam M. Mallon was Executive Vice President, ExxonMobil Development Company February 1, 2014 – December 31, 2016. He was President of ExxonMobil Development Company January 1, 2017 – March 31, 2019. He became President of ExxonMobil Upstream Oil & Gas Company and Vice President of Exxon Mobil Corporation on April 1, 2019, positions he continues to hold as of this filing date.

Karen T. McKee	*Vice President*	
Held current title since:	April 1, 2019	Age: 54

Ms. Karen T. McKee was Vice President, Basic Chemicals, ExxonMobil Chemical Company May 1, 2014 – July 31, 2017. She was Senior Vice President, Basic Chemicals, Integration & Growth, ExxonMobil Chemical Company August 1, 2017 – March 31, 2019. She became President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation on April 1, 2019, positions she continues to hold as of this filing date.

Craig S. Morford	*Vice President and General Counsel*	
Held current title since:	November 1, 2020	Age: 62

Mr. Craig S. Morford was Chief Legal and Compliance Officer of Cardinal Heath, Inc. prior to joining Exxon Mobil Corporation in May 2019. He was Deputy General Counsel of Exxon Mobil Corporation May 1, 2019 - October 31, 2020. He became Vice President and General Counsel of Exxon Mobil Corporation on November 1, 2020, positions he continues to hold as of this filing date.

David S. Rosenthal	*Vice President and Controller*	
Held current title since:	October 1, 2008 (Vice President) September 1, 2014 (Controller)	Age: 64

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.

James M. Spellings, Jr.	*Vice President – Treasurer and General Tax Counsel*	
Held current title since:	March 1, 2010 (Vice President and General Tax Counsel) April 1, 2020 (Treasurer)	Age: 59

Mr. James M. Spellings, Jr. became Vice President and General Tax Counsel of Exxon Mobil Corporation March 1, 2010 and Treasurer of Exxon Mobil Corporation on April 1, 2020, positions he continues to hold as of this filing date.

Theodore J. Wojnar, Jr.	*Vice President – Corporate Strategic Planning*

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. The above-named officers are required to file reports under Section 16 of the Securities Exchange Act of 1934.

PART II

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

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 343,633 registered shareholders of ExxonMobil common stock at December 31, 2020. At January 31, 2021, the registered shareholders of ExxonMobil common stock numbered 341,925.

On January 27, 2021, the Corporation declared an $0.87 dividend per common share, payable March 10, 2021.

Reference is made to Item 12 in Part III of this report.

Issuer Purchases of Equity Securities for Quarter Ended December 31, 2020

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 2020	-		-	
November 2020	-		-	
December 2020	-		-	
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 - In its earnings release dated February 2, 2021, the Corporation stated that it had suspended its first quarter 2021 anti-dilutive share repurchase program due to market uncertainty and intends to resume this program in the future as market conditions improve.

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 24, 2021, beginning with the section entitled “Report of Independent Registered Public Accounting Firm” and continuing through “Note 20: Restructuring Activities”;
- “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, 2020. 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, 2020.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation’s internal control over financial reporting as of December 31, 2020, 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 “Information about our Executive Officers”.

Incorporated by reference to the following from the registrant’s definitive proxy statement for the 2021 annual meeting of shareholders (the “2021 Proxy Statement”):

- The section entitled “Election of Directors”;
- The portion entitled “Delinquent Section 16(a) Reports” of the section entitled “Director and Executive Officer Stock Ownership”;
- The portions entitled “Director Qualifications”, “Director Nomination Process and 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 2021 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 2021 Proxy Statement.

Equity Compensation Plan Information

Plan Category	*(a)* Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	*(b)* Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	*(c)* Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	42,714,580 *(1)*	—	70,944,592 *(2)(3)*
Equity compensation plans not approved by security holders	—	—	—
Total	42,714,580	—	70,944,592

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

(2) Available shares can be granted in the form of restricted stock or other stock-based awards. Includes 70,523,392 shares available for award under the 2003 Incentive Program and 421,200 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 portion entitled "Related Person Transactions and Procedures" of the section entitled "Director and Executive Officer Stock Ownership"; and the portion entitled "Director Independence" of the section entitled "Corporate Governance" of the registrant's 2021 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 2021 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.

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

ITEM 16. FORM 10-K SUMMARY

None.

FINANCIAL SECTION

TABLE OF CONTENTS

BUSINESS PROFILE

Financial	Earnings (Loss) After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
	2020	2019	2020	2019	2020	2019	2020	2019
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	(19,385)	536	65,780	72,152	(29.5)	0.7	6,817	11,653
Non-U.S.	(645)	13,906	107,506	107,271	(0.6)	13.0	7,614	11,832
Total	(20,030)	14,442	173,286	179,423	(11.6)	8.0	14,431	23,485
Downstream								
United States	(852)	1,717	11,472	9,515	(7.4)	18.0	2,344	2,353
Non-U.S.	(225)	606	18,682	18,518	(1.2)	3.3	1,877	2,018
Total	(1,077)	2,323	30,154	28,033	(3.6)	8.3	4,221	4,371
Chemical								
United States	1,277	206	14,436	13,196	8.8	1.6	2,002	2,547
Non-U.S.	686	386	17,600	18,113	3.9	2.1	714	718
Total	1,963	592	32,036	31,309	6.1	1.9	2,716	3,265
Corporate and financing	(3,296)	(3,017)	(1,445)	(2,162)	—	—	6	27
Total	(22,440)	14,340	234,031	236,603	(9.3)	6.5	21,374	31,148

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

Operating	2020	2019		2020	2019
	(thousands of barrels daily)			*(thousands of barrels daily)*	
Net liquids production			Refinery throughput		
United States	685	646	United States	1,549	1,532
Non-U.S.	1,664	1,740	Non-U.S.	2,224	2,449
Total	2,349	2,386	Total	3,773	3,981
	(millions of cubic feet daily)			*(thousands of barrels daily)*	
Natural gas production available for sale			Petroleum product sales *(2)*		
United States	2,691	2,778	United States	2,154	2,292
Non-U.S.	5,780	6,616	Non-U.S.	2,741	3,160
Total	8,471	9,394	Total	4,895	5,452
	(thousands of oil-equivalent barrels daily)			*(thousands of metric tons)*	
Oil-equivalent production *(1)*	3,761	3,952	Chemical prime product sales *(2) (3)*		
			United States	9,010	9,127
			Non-U.S.	16,439	17,389
			Total	25,449	26,516

(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

	2020	2019	2018
	(millions of dollars, except where stated otherwise)		
Sales and other operating revenue	178,574	255,583	279,332
Earnings (Loss)			
Upstream	(20,030)	14,442	14,079
Downstream	(1,077)	2,323	6,010
Chemical	1,963	592	3,351
Corporate and financing	(3,296)	(3,017)	(2,600)
Net income (loss) attributable to ExxonMobil	(22,440)	14,340	20,840
Earnings (Loss) per common share (dollars)	(5.25)	3.36	4.88
Earnings (Loss) per common share – assuming dilution (dollars)	(5.25)	3.36	4.88
Earnings (Loss) to average ExxonMobil share of equity (percent)	(12.9)	7.5	11.0
Working capital	(11,470)	(13,937)	(9,165)
Ratio of current assets to current liabilities (times)	0.80	0.78	0.84
Additions to property, plant and equipment	17,342	24,904	20,051
Property, plant and equipment, less allowances	227,553	253,018	247,101
Total assets	332,750	362,597	346,196
Exploration expenses, including dry holes	1,285	1,269	1,466
Research and development costs	1,016	1,214	1,116
Long-term debt	47,182	26,342	20,538
Total debt	67,640	46,920	37,796
Debt to capital (percent)	29.2	19.1	16.0
Net debt to capital (percent) *(1)*	27.8	18.1	14.9
ExxonMobil share of equity at year-end	157,150	191,650	191,794
ExxonMobil share of equity per common share (dollars)	37.12	45.26	45.27
Weighted average number of common shares outstanding (millions)	4,271	4,270	4,270
Number of regular employees at year-end (thousands) *(2)*	72.0	74.9	71.0

(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.

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 assets are contributing to the Corporation's strategic objectives. Assets are divested when they are no longer meeting these objectives or are worth considerably more to others. Because of the regular nature of this activity, we believe it is useful for investors to consider proceeds associated with asset sales together with cash provided by operating activities when evaluating cash available for investment in the business and financing activities, including shareholder distributions.

Cash flow from operations and asset sales	2020	2019	2018
		(millions of dollars)	
Net cash provided by operating activities	14,668	29,716	36,014
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	999	3,692	4,123
Cash flow from operations and asset sales	15,667	33,408	40,137

Capital Employed

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

Capital employed	2020	2019	2018
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	332,750	362,597	346,196
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(35,905)	(43,411)	(39,880)
Total long-term liabilities excluding long-term debt	(65,075)	(73,328)	(69,992)
Noncontrolling interests share of assets and liabilities	(8,773)	(8,839)	(7,958)
Add ExxonMobil share of debt-financed equity company net assets	4,140	3,906	3,914
Total capital employed	227,137	240,925	232,280
Total corporate sources: debt and equity perspective			
Notes and loans payable	20,458	20,578	17,258
Long-term debt	47,182	26,342	20,538
ExxonMobil share of equity	157,150	191,650	191,794
Less noncontrolling interests share of total debt	(1,793)	(1,551)	(1,224)
Add ExxonMobil share of equity company debt	4,140	3,906	3,914
Total capital employed	227,137	240,925	232,280

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. Additional measures, which are more cash flow based, are used to make investment decisions.

Return on average capital employed	**2020**	**2019**	**2018**
	(millions of dollars)		
Net income (loss) attributable to ExxonMobil	(22,440)	14,340	20,840
Financing costs (after tax)			
Gross third-party debt	(1,272)	(1,075)	(912)
ExxonMobil share of equity companies	(182)	(207)	(192)
All other financing costs – net	666	141	498
Total financing costs	(788)	(1,141)	(606)
Earnings (Loss) excluding financing costs	(21,652)	15,481	21,446
Average capital employed	234,031	236,603	232,374
Return on average capital employed – corporate total	(9.3)%	6.5 %	9.2 %

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

FUNCTIONAL EARNINGS	2020	2019	2018
	(millions of dollars, except per share amounts)		
Earnings (Loss) (U.S. GAAP)			
Upstream			
United States	(19,385)	536	1,739
Non-U.S.	(645)	13,906	12,340
Downstream			
United States	(852)	1,717	2,962
Non-U.S.	(225)	606	3,048
Chemical			
United States	1,277	206	1,642
Non-U.S.	686	386	1,709
Corporate and financing	(3,296)	(3,017)	(2,600)
Net income (loss) attributable to ExxonMobil (U.S. GAAP)	(22,440)	14,340	20,840
Earnings (Loss) per common share	(5.25)	3.36	4.88
Earnings (Loss) per common share – assuming dilution	(5.25)	3.36	4.88

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

FORWARD-LOOKING STATEMENTS

Outlooks, projections, goals, targets, descriptions of strategic plans and objectives, and other statements of future events or conditions in this release are forward-looking statements. Actual future results, including energy demand growth and mix; financial and operating performance; volume growth; project plans, timing, costs, and capacities; capital expenditures including environmental expenditures; cost reductions; emission intensity reductions; the impact of new technologies; capital expenditures and mix; investment returns; accounting and financial reporting effects resulting from market developments and ExxonMobil's responsive actions, including potential impairment charges; the benefits of business integration; future debt levels and ability to reduce debt; the outcome of litigation and tax contingencies; and the impact of the COVID-19 pandemic on results, could differ materially due to a number of factors. These include global or regional changes in the supply and demand for oil, natural gas, petrochemicals, and feedstocks and other market conditions that impact prices and differentials; the impact of company actions to protect the health and safety of employees, vendors, customers, and communities; actions of competitors and commercial counterparties; the ability to access short- and long-term debt markets on a timely and affordable basis; the severity, length and ultimate impact of COVID-19 and government responses on people and economies; reservoir performance; the outcome of exploration projects and timely completion of development and construction projects; changes in law, taxes, or regulation including environmental regulations, and timely granting of governmental permits; war, trade agreements and patterns, shipping blockades or harassment, and other political or security disturbances; opportunities for and regulatory approval of potential investments or divestments; the actions of competitors; the capture of efficiencies within and between business lines and the ability to maintain near-term cost reductions as ongoing efficiencies while maintaining future competitive positioning; unforeseen technical or operating difficulties; the development and competitiveness of alternative energy and emission reduction technologies; the results of research programs; the ability to bring new technologies to commercial scale on a cost-competitive basis; general economic conditions including the occurrence and duration of economic recessions; and other factors discussed under Item 1A. Risk Factors.

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, generally 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 operating and capital objectives in addition to providing the economic assumptions used for investment evaluation purposes. Volume projections are based on individual field production profiles, which are also updated at least 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.

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

Given the uncertainty around the near-term impacts of COVID-19 on economic growth, energy demand and energy supply, and lack of precedent, the Company is considering a range of recovery pathways to guide near-term plans. These pathways expect that energy demand will grow beyond 2019 levels as early as 2022 reflecting the phase out of COVID-19 impacts and re-establishment of long-term supply/demand fundamentals. The Corporation's Outlook for Energy combined with the near-term pathways are used to help inform our long-term business strategies and investment plans.

By 2040, the world's population is projected at around 9.1 billion people, or about 1.6 billion more than in 2018. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 2.5 percent per year, with economic output growing by around 75 percent 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 more than 10 percent from 2018 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 products 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 50 percent from 2018 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 20 percent of the world's electricity in 2040, versus nearly 40 percent in 2018, in part as a result of policies to improve air quality as well as reduce greenhouse gas emissions to address the risks related to climate change. From 2018 to 2040, the amount of electricity supplied using natural gas, nuclear power, and renewables is likely to nearly double, accounting for the entire growth in electricity supplies and offsetting the reduction of coal. 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 80 percent of the increase in electricity supplies worldwide through 2040. Total renewables will likely reach about 50 percent of global electricity supplies by 2040. Natural gas and nuclear are also expected to increase shares over the period to 2040, reaching more than 25 percent and about 10 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 and policy developments.

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 20 percent from 2018 to 2040. Transportation energy demand is likely to account for over 60 percent of the growth in liquid fuels demand worldwide over this period. Light-duty vehicle demand for liquid fuels is projected to peak prior to 2025 and then decline to levels seen in the early-2010s by 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 60 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 commercial 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 110 million barrels of oil equivalent per day, an increase of about 9 percent from 2018. 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 15 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 and lower carbon supply options. However, timely investments will remain critical to meeting global needs with reliable and affordable supplies.

Natural gas is a lower-emission, versatile and practical fuel for a wide variety of applications, and it is expected to grow the most of any primary energy type from 2018 to 2040, meeting about 50 percent of global energy demand growth. Global natural gas demand is expected to rise about 25 percent from 2018 to 2040, with about half of that increase coming from 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 more than two thirds of worldwide demand in 2040. Liquefied natural gas (LNG) trade will expand significantly, meeting about 40 percent of the increase in global demand growth, with much of this supply expected to help meet rising demand in Asia Pacific.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to 30 percent in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas in the next few years. The share of natural gas is expected to reach more than 25 percent by 2040, while the share of coal falls to about two thirds of the natural gas share. 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 over 350 percent from 2018 to 2040, when they will likely be just over 6 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 as the International Energy Agency (IEA) describes in its *World Energy Outlook 2020*. According to the IEA's Stated Energy Policies Scenario, the investment required to meet oil and natural gas supply requirements worldwide over the period 2019-2040 will be about $17 trillion (measured in 2019 dollars). In the IEA's Sustainable Development Scenario, which is in line with the objectives of the Paris Agreement on climate change, the investment need would still accumulate to $12 trillion.

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 (NDCs), 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_2 emissions is assumed to reach about $80 per tonne 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. The Corporation continues to monitor the updates to the NDCs that nations are expected to provide in preparation for COP 26 in Glasgow in November 2021 as well as other policy developments in light of net zero ambitions recently formulated by some nations.

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

Positioning for a Lower-Carbon Energy Future

Practical solutions to the world's energy and climate challenges will benefit from market competition in addition to 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 and affordable energy, and economic progress for all people. ExxonMobil encourages sound policy solutions that reduce climate-related risks across the economy at the lowest societal cost. All practical and economically-viable energy sources 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.

ExxonMobil is committed to advancing sustainable, effective solutions that address both the world's growing demand for energy and the risks of climate change. The Company's plans aim for industry-leading greenhouse gas performance across its businesses by 2030. These plans include a reduction of the intensity of operated upstream greenhouse gas emissions by 15 to 20 percent in 2025, compared to 2016 levels, which will be supported by a 40 to 50 percent decrease in methane intensity and a 35 to 45 percent decrease in flaring intensity across the Corporation's global operations. The 2025 emission reduction plans are expected to result in a reduction of absolute emissions by approximately 30 percent for the Company's current Upstream business by 2025 when compared to 2016 levels. The emission plans cover Scope 1 and Scope 2 emissions from assets operated by the Corporation.

Commercially viable technology advances will be needed to achieve the Paris Agreement objectives at the lowest societal cost. While many potential pathways exist, ExxonMobil cannot predict how these objectives will become achievable given the range of uncertainties. ExxonMobil is working to develop breakthrough solutions in areas such as carbon capture, biofuels, hydrogen, and energy-efficiency process technology that can help achieve the Paris Agreement objectives. In early 2021 ExxonMobil announced the creation of a new business, ExxonMobil Low Carbon Solutions, to commercialize low-carbon technologies. The business will initially focus on carbon capture and storage (CCS), one of the critical technologies required to achieve the climate objectives outlined in the Paris Agreement. In addition to CCS, the business will also leverage ExxonMobil's significant experience in the production of hydrogen which, when coupled with CCS, is likely to play a critical role in a lower-carbon energy system. Other technology focus areas will be added in the future as they mature to commercialization.

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, the proportion of oil-equivalent production from the Americas is generally expected to increase over the next several years. Further, the proportion of our global production from unconventional and deepwater resources, as well as LNG currently contributes nearly half of global production, and is generally expected to grow in the next few years.

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. Market demand and prices experienced sharp decline in the first half of 2020 largely driven by the COVID-19 pandemic. Following this decline, prices increased in the second half of the year as supply and demand began to rebalance. 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 2020, the Upstream business produced 3.8 million oil-equivalent barrels per day and matched best-ever reliability performance with continued focus on delivering best in class operations in all aspects of the business while prioritizing cash flow generation and return on investment. Government-mandated and economic curtailments negatively impacted 2020 production by approximately 0.2 million oil-equivalent barrels per day. Significant progress was made on key new developments in Guyana and in the Permian basin during 2020. In Guyana, exploration success continued with three additional discoveries increasing the estimated recoverable resource to nearly 9 billion oil-equivalent barrels on the Stabroek block. In the Permian, despite economic curtailments and reduced capital investment, production volumes averaged 367 thousand oil-equivalent barrels per day in 2020, a 35 percent year-on-year production increase which exceeded expectations, while development and operating costs were significantly reduced. Also in the Permian, we started up the Delaware basin central processing and stabilization facility which enhances the company's integration advantages by collecting and processing oil and natural gas for delivery to Gulf Coast markets.

Downstream

ExxonMobil's Downstream is a large, diversified business with global logistics, trading, refining, and marketing. The Corporation has a well-established presence in the Americas, Europe, and growing Asia Pacific region.

Downstream strategies competitively position the business across a range of market conditions. These strategies focus on providing quality, differentiated, and valued products and services to customers, targeting best in class operations performance, capitalizing on integration across all ExxonMobil businesses, maximizing value from advantaged technology, and selectively investing for resilient, advantaged returns.

ExxonMobil's operating results, as noted in Item 2. Properties, reflect 21 refineries, located in 14 countries, with distillation capacity of 4.8 million barrels per day (MBD) and lubricant base stock manufacturing capacity of 129 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*.

Fuels demand in 2020 was significantly impacted by the COVID-19 pandemic. During the second quarter downturn, global demand for gasoline, diesel, and jet fuel declined about 23 percent versus 2019. While demand partially recovered in the second half of the year, fourth quarter total products demand remained 10 percent below 2019 levels. This unprecedented demand impact adversely affected refining margins resulting in historically low market conditions, with announced refinery closures four times higher than 10-year historical levels. In the near-term, refining margins will continue to be impacted by COVID-19 demand recovery. Finished lubricant demand was also impacted by COVID-19, with ExxonMobil's estimate of industry demand down 5 to 10 percent versus 2019.

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 and the market prices for the range of products produced. 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 shifting consumer demand as well as capacity changes from refinery additions and closures. ExxonMobil's significant integration both within the Downstream value chains including lubricants, logistics, trading, refining, and marketing, as well as with Upstream and Chemical, improves our ability to generate shareholder value in different market conditions.

As described 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.

ExxonMobil continually evaluates the Downstream portfolio during all phases of the business cycle, which has resulted in numerous asset divestments over the past decade to strengthen overall profitability and resiliency. When investing in the Downstream, ExxonMobil remains focused on select and resilient projects across a broad range of market conditions. In 2020, the Strathcona Cogeneration project started up to improve refinery energy efficiency and reduce greenhouse gas emissions. In addition, the main segment of the Wink to Webster pipeline system, operated by ExxonMobil Pipeline Company, started transporting Permian crude from Midland to Houston. Finally, deferral costs associated with pacing previously announced Downstream projects will be offset with efficiencies captured during the market downturn.

ExxonMobil continues to grow fuels product sales in new markets near major production assets with continued progress in the Mexico and Indonesia market entries. 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*, ExxonMobil is the worldwide leader in synthetic motor oils.

Chemical

ExxonMobil is a major manufacturer and marketer of petrochemicals, including a wide variety of performance products that sustainably support improved living standards around the globe. ExxonMobil sustains its competitive advantage through continued operational excellence, investment and cost discipline, a balanced portfolio of products, and unparalleled integration with Downstream and Upstream operations, all underpinned by proprietary technology.

In 2020, many markets were heavily impacted by COVID-19, however demand for chemical products remained resilient in several key segments including food packaging, hygiene and medical. Overall Chemical margins improved compared to 2019 due to lower feedstock costs, continued strong packaging demand, and industry supply disruptions through the second half of 2020. We were uniquely positioned to capture value from the market volatility in 2020 due to our integration, enabling nimble feed and product optimization. This, in addition to our outstanding safety and reliability performance and structural cost improvement, delivered industry leading earnings.

Over the long term, demand for chemical products is forecast to outpace growth in global GDP and energy demand. ExxonMobil estimates that worldwide demand for chemicals will rise by over 40 percent by 2030, driven by continued global population growth and an expanding middle class. ExxonMobil's integration with refining, together with our high-value performance products and unique project execution capability, enhances our ability to generate industry-leading returns on investments across a range of market environments. In 2020, construction progressed on our joint venture ethane cracker and associated units near Corpus Christi, Texas. The project is below budget and expected to start up ahead of schedule in the fourth quarter of 2021. We made the decision to slow the pace of other U.S. Gulf Coast growth projects, capturing current market efficiencies to offset deferral costs. In addition, we continued to progress plans for a world-scale steam cracker and performance derivative units in Guangdong Province, China.

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

REVIEW OF 2020 AND 2019 RESULTS

During the first and second quarters of 2020, the balance of supply and demand for petroleum and petrochemical products experienced two significant disruptive effects. On the demand side, the COVID-19 pandemic spread rapidly through most areas of the world resulting in substantial reductions in consumer and business activity and significantly reduced demand for crude oil, natural gas, and petroleum products. This reduction in demand coincided with announcements of increased production in certain key oil-producing countries which led to increases in inventory levels and sharp declines in prices for crude oil, natural gas, and petroleum products.

Market conditions continued to reflect considerable uncertainty throughout 2020 as consumer and business activity exhibited some degree of recovery, but remained lower when compared to prior periods as a result of the pandemic. Despite actions taken by key oil-producing countries to reduce oversupply, the unfavorable economic impacts are likely to persist to some extent well into 2021.

	2020	2019	2018
		(millions of dollars)	
Earnings (Loss) (U.S. GAAP)			
Net income (loss) attributable to ExxonMobil (U.S. GAAP)	(22,440)	14,340	20,840

Upstream

	2020	2019	2018
		(millions of dollars)	
Upstream			
United States	(19,385)	536	1,739
Non-U.S.	(645)	13,906	12,340
Total	(20,030)	14,442	14,079

2020

Upstream results were a loss of $20,030 million, down $34,472 million from 2019.

- Lower realizations reduced earnings by $11.2 billion.
- Unfavorable volume and mix effects decreased earnings by $300 million.
- All other items decreased earnings by $23 billion, as impairments of $19.4 billion and the absence of the $3.7 billion gain from the 2019 Norway non-operated divestment were partly offset by lower expenses of $1 billion.
- U.S. Upstream results were a loss of $19,385 million and included asset impairments of $17.1 billion.
- Non-U.S. Upstream results were a loss of $645 million, including asset impairments of $2.3 billion and the absence of the $3.7 billion gain from the Norway non-operated divestment.
- On an oil-equivalent basis, production of 3.8 million barrels per day was down 5 percent compared to 2019.

- Liquids production of 2.3 million barrels per day decreased 37,000 barrels per day reflecting the impacts of government mandates, divestments, and lower demand, partly offset by growth and lower downtime.
- Natural gas production of 8.5 billion cubic feet per day decreased 923 million cubic feet per day from 2019, reflecting divestments, lower demand, and higher downtime, partly offset by growth.

2019

Upstream earnings were $14,442 million, up $363 million from 2018.

- Lower realizations reduced earnings by $2.7 billion.
- Favorable volume and mix effects increased earnings by $860 million.
- All other items increased earnings by $2.2 billion, as a $3.7 billion gain from the Norway non-operated divestment was partly offset by higher expenses of $1.1 billion.
- U.S. Upstream earnings were $536 million and included asset impairments of $146 million.
- Non-U.S. Upstream earnings were $13,906 million, including the $3.7 billion gain from the Norway non-operated divestment.
- On an oil-equivalent basis, production of 4.0 million barrels per day was up 3 percent compared to 2018.
- Liquids production of 2.4 million barrels per day increased 120,000 barrels per day reflecting growth and higher entitlements.
- Natural gas production of 9.4 billion cubic feet per day decreased 11 million cubic feet per day from 2018, with the impact from divestments and higher downtime offset by growth and higher entitlements.

Upstream Additional Information

	2020	2019
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production) *(1)*		
Prior Year	3,952	3,833
Entitlements - Net Interest	(9)	(1)
Entitlements - Price / Spend / Other	67	34
Government Mandates	(110)	(3)
Divestments	(151)	(27)
Growth / Other	12	116
Current Year	3,761	3,952

(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.

Government Mandates are changes to ExxonMobil's sustainable production levels due to temporary non-operational production limits imposed by governments, generally upon a sector, type or method of production.

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

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

Downstream

	2020	2019	2018
		(millions of dollars)	
Downstream			
United States	(852)	1,717	2,962
Non-U.S.	(225)	606	3,048
Total	(1,077)	2,323	6,010

2020

Downstream results of a $1,077 million loss decreased $3,400 million from 2019.

- Margins decreased earnings by $3.8 billion including the impact of weaker industry refining conditions.
- Volume and mix effects increased earnings by $370 million as manufacturing/yield improvement impacts were partly offset by weaker demand.
- All other items increased earnings by $50 million, as lower expenses of $1.3 billion were offset by impairments of $620 million, unfavorable LIFO inventory impacts of $410 million, and unfavorable tax items of $240 million.
- U.S. Downstream results were a loss of $852 million, compared to earnings of $1,717 million in the prior year.
- Non-U.S. Downstream results were a loss of $225 million, compared to earnings of $606 million in the prior year.
- Petroleum product sales of 4.9 million barrels per day were 557,000 barrels per day lower than 2019.

2019

Downstream earnings of $2,323 million decreased $3,687 million from 2018.

- Margins decreased earnings by $3 billion including the impact of lower North American crude differentials.
- Volume and mix effects lowered earnings by $50 million as project contributions and portfolio improvement were more than offset by increased downtime/maintenance and unfavorable yield/sales mix.
- All other items decreased earnings by $660 million, mainly driven by the absence of prior year divestment gains and higher expenses reflecting increased maintenance and project startups, partly offset by favorable foreign exchange impacts and LIFO inventory gains.
- U.S. Downstream earnings were $1,717 million, compared to $2,962 million in the prior year.
- Non-U.S. Downstream earnings were $606 million, compared to $3,048 million in the prior year.
- Petroleum product sales of 5.5 million barrels per day were 60,000 barrels per day lower than 2018.

Chemical

	2020	2019	2018
		(millions of dollars)	
Chemical			
United States	1,277	206	1,642
Non-U.S.	686	386	1,709
Total	1,963	592	3,351

2020

Chemical earnings of $1,963 million increased $1,371 million from 2019.

- Stronger margins increased earnings by $930 million.
- Volume and mix effects decreased earnings by $150 million.
- All other items increased earnings by $590 million as lower expenses of $710 million were partly offset by unfavorable one-time items, mainly impairments.
- U.S. Chemical earnings were $1,277 million in 2020, compared with $206 million in the prior year.
- Non-U.S. Chemical earnings were $686 million, compared with $386 million in the prior year.
- Prime product sales of 25.4 million metric tons were down 1.1 million metric tons from 2019.

2019

Chemical earnings of $592 million decreased $2,759 million from 2018.

- Weaker margins decreased earnings by $1.8 billion.
- Volume and mix effects were essentially flat, as lower sales volumes were offset by new asset contributions.
- All other items decreased earnings by $940 million, primarily due to higher expenses associated with new assets, business growth, and maintenance activity, the absence of a favorable tax item in the prior year, and unfavorable foreign exchange impacts.
- U.S. Chemical earnings were $206 million in 2019, compared with $1,642 million in the prior year.
- Non-U.S. Chemical earnings were $386 million, compared with $1,709 million in the prior year.
- Prime product sales of 26.5 million metric tons were down 0.4 million metric tons from 2018.

Corporate and Financing

	2020	2019	2018
		(millions of dollars)	
Corporate and financing	(3,296)	(3,017)	(2,600)

2020

Corporate and financing expenses were $3,296 million in 2020 compared to $3,017 million in 2019, with the increase mainly due to higher financing costs and employee severance costs, partly offset by lower corporate costs.

2019

Corporate and financing expenses were $3,017 million in 2019 compared to $2,600 million in 2018, with the increase mainly due to unfavorable tax impacts and higher financing costs.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2020	2019	2018
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	14,668	29,716	36,014
Investing activities	(18,459)	(23,084)	(16,446)
Financing activities	5,285	(6,618)	(19,446)
Effect of exchange rate changes	(219)	33	(257)
Increase/(decrease) in cash and cash equivalents	1,275	47	(135)
		(December 31)	
Total cash and cash equivalents	4,364	3,089	3,042

Total cash and cash equivalents were $4.4 billion at the end of 2020, up $1.3 billion from the prior year. The major sources of funds in 2020 were the adjustment for the noncash provision of $46.0 billion for depreciation and depletion, a net debt increase of $20.1 billion, proceeds from asset sales of $1.0 billion, and other investing activities of $2.7 billion. The major uses of funds included a net loss including noncontrolling interests of $23.3 billion, spending for additions to property, plant and equipment of $17.3 billion, dividends to shareholders of $14.9 billion, and additional investments and advances of $4.9 billion.

Total cash and cash equivalents were $3.1 billion at the end of 2019, up $47 million from the prior year. The major sources of funds in 2019 were net income including noncontrolling interests of $14.8 billion, the adjustment for the noncash provision of $19.0 billion for depreciation and depletion, a net debt increase of $8.7 billion, and proceeds from asset sales of $3.7 billion. The major uses of funds included spending for additions to property, plant and equipment of $24.4 billion, dividends to shareholders of $14.7 billion, and additional investments and advances of $3.9 billion.

The Corporation has access to significant capacity of long-term and short-term liquidity. Commercial paper continues to provide short-term liquidity, and is reflected in "Notes and loans payable" on the Consolidated Balance Sheet with changes in outstanding commercial paper between periods included in the Consolidated Statement of Cash Flows. The Corporation took steps to strengthen its liquidity in 2020, including issuing $23.2 billion of long-term debt and implementing significant capital and operating cost reductions. The Corporation ended the year with $68 billion in gross debt and intends to reduce debt over time. On December 31, 2020, the Corporation had unused short-term committed lines of credit of $11.3 billion and no unused long-term lines of credit.

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. 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. In particular, the Corporation's key tight-oil plays have higher initial decline rates which tend to moderate over time. 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 mitigating 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 2020 were $21.4 billion, reflecting the Corporation's continued active investment program. The Corporation is prioritizing opportunities to hold 2021 capital spending in a range of $16 billion to $19 billion.

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 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.

The Corporation, as part of its ongoing asset management program, continues to evaluate its mix of assets for potential upgrade. Because of the ongoing nature of this program, dispositions will continue to be made from time to time which will result in either gains or losses. In light of the current low commodity price environment, and depending on the extent and pace of recovery, the Corporation's planned divestment program could be adversely affected by fewer financially suitable buyers. This could result in a slowing of the pace of divestments, certain assets being sold at a price below current book value, or impairment charges if the likelihood of divesting certain assets increases. Additionally, the Corporation continues to evaluate opportunities to enhance its business portfolio through acquisitions of assets or companies, and enters into such transactions from time to time. Key criteria for evaluating acquisitions include potential for future growth and attractive current valuations. Acquisitions may be made with cash, shares of the Corporation's common stock, or both.

ExxonMobil closely monitors the potential impacts of Brexit and Interbank Offered Rate (IBOR) reforms, including LIBOR, 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

2020

Cash provided by operating activities totaled $14.7 billion in 2020, $15.0 billion lower than 2019. Net income (loss) including noncontrolling interests was a loss of $23.3 billion, a decrease of $38.0 billion. The noncash provision for depreciation and depletion was $46.0 billion, up $27.0 billion from the prior year, mainly due to asset impairments. The noncash provision for deferred income tax benefits was $8.9 billion and also included impacts from asset impairments. The adjustment for the net loss on asset sales was $4 million, a decrease of $1.7 billion. The adjustment for dividends received less than equity in current earnings of equity companies was an increase of $1.0 billion, compared to a reduction of $0.9 billion in 2019. Changes in operational working capital, excluding cash and debt, decreased cash in 2020 by $1.7 billion.

2019

Cash provided by operating activities totaled $29.7 billion in 2019, $6.3 billion lower than 2018. The major source of funds was net income including noncontrolling interests of $14.8 billion, a decrease of $6.6 billion. The noncash provision for depreciation and depletion was $19.0 billion, up $0.3 billion from the prior year. The adjustment for the net gain on asset sales was $1.7 billion, a decrease of $0.3 billion. The adjustment for dividends received less than equity in current earnings of equity companies was a reduction of $0.9 billion, compared to a reduction of $1.7 billion in 2018. Changes in operational working capital, excluding cash and debt, increased cash in 2019 by $0.9 billion.

Cash Flow from Investing Activities

2020

Cash used in investing activities netted to $18.5 billion in 2020, $4.6 billion lower than 2019. Spending for property, plant and equipment of $17.3 billion decreased $7.1 billion from 2019. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $1.0 billion compared to $3.7 billion in 2019. Additional investments and advances were $1.0 billion higher in 2020, while proceeds from other investing activities including collection of advances increased by $1.2 billion.

2019

Cash used in investing activities netted to $23.1 billion in 2019, $6.6 billion higher than 2018. Spending for property, plant and equipment of $24.4 billion increased $4.8 billion from 2018. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $3.7 billion compared to $4.1 billion in 2018. Additional investments and advances were $1.9 billion higher in 2019, while proceeds from other investing activities including collection of advances increased by $0.5 billion.

Cash Flow from Financing Activities

2020

Cash flow from financing activities was $5.3 billion in 2020, $11.9 billion higher than 2019. Dividend payments on common shares increased to $3.48 per share from $3.43 per share and totaled $14.9 billion. During 2020, the Corporation issued $23.2 billion of long-term debt. Total debt increased $20.7 billion to $67.6 billion at year-end.

ExxonMobil share of equity decreased $34.5 billion to $157.2 billion. The reduction to equity for losses was $22.4 billion and the reduction for distributions to ExxonMobil shareholders was $14.9 billion, all in the form of dividends. Foreign exchange translation effects of $1.8 billion for the weaker U.S. dollar and a $1.0 billion change in the funded status of the postretirement benefits reserves increased equity.

During 2020, 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 4,234 million to 4,233 million at the end of 2020.

2019

Cash used in financing activities was $6.6 billion in 2019, $12.8 billion lower than 2018. Dividend payments on common shares increased to $3.43 per share from $3.23 per share and totaled $14.7 billion. During the third quarter of 2019, the Corporation issued $7.0 billion of long-term debt. Total debt increased $9.1 billion to $46.9 billion at year-end.

ExxonMobil share of equity decreased $0.1 billion to $191.7 billion. The addition to equity for earnings was $14.3 billion. This was offset by reductions for distributions to ExxonMobil shareholders of $14.7 billion, all in the form of dividends. Foreign exchange translation effects of $1.4 billion for the weaker U.S. currency increased equity, while a $1.4 billion change in the funded status of the postretirement benefits reserves reduced equity.

During 2019, 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 4,237 million to 4,234 million at the end of 2019.

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2020. The table combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

		Payments Due by Period				
Commitments	**Note Reference Number**	**2021**	**2022-2023**	**2024-2025**	**2026 and Beyond**	**Total**
			(millions of dollars)			
Long-term debt excluding finance lease obligations *(1)*	6, 14	2,828	7,364	8,640	29,263	48,095
Asset retirement obligations *(2)*	9	689	1,203	1,005	8,350	11,247
Pension and other postretirement obligations *(3)*	17	1,860	1,576	1,530	16,495	21,461
Lease commitments *(4)*	11					
Operating and finance leases - commenced		1,558	2,163	1,358	2,004	7,083
Operating and finance leases - not yet commenced		192	1,081	495	2,786	4,554
Take-or-pay and unconditional purchase obligations *(5)*		4,155	7,246	5,626	16,932	33,959
Firm capital commitments *(6)*		6,027	4,469	1,689	599	12,784

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 $8.8 billion as of December 31, 2020, 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) The amount due in 2021 is included in Notes and loans payable of $20,458 million. The amounts due 2022 and beyond are included in Long-term debt of $47,182 million.

(2) Asset retirement obligations are primarily upstream asset removal costs at the end of field life.

(3) The amount by which the benefit obligations exceeded the fair value of fund assets for 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 2021 and estimated benefit payments for unfunded plans in all years.

(4) Commitments for operating and finance leases cover drilling equipment, tankers and other assets.

(5) 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 obligations mainly pertain to pipeline, manufacturing supply and terminal agreements.

(6) 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 $12.8 billion, including $5.3 billion in the U.S.

Firm capital commitments for the non-U.S. Upstream of $5.9 billion were primarily associated with projects in Guyana, Angola, Malaysia, United Kingdom, Canada, Australia, Brazil and United Arab Emirates. The Corporation expects to fund the majority of these commitments with internally generated funds, supplemented by short-term and long-term debt as required.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2020, 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, 2020, the Corporation had total unused short-term committed lines of credit of $11.3 billion (Note 6) and no unused long-term lines of credit (Note 14). The table below shows the Corporation's consolidated debt to capital ratios.

	2020	2019	2018
Debt to capital (percent)	29.2	19.1	16.0
Net debt to capital (percent)	27.8	18.1	14.9

Management views the Corporation's financial strength to be a competitive advantage of strategic importance. The Corporation's 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.

Industry conditions in 2020 led to lower realized prices for the Corporation's products which resulted in substantially lower earnings and operating cash flow in comparison to 2019. The Corporation took steps to strengthen its liquidity in 2020, including issuing $23 billion of long-term debt and implementing significant capital and operating cost reductions. The Corporation ended the year with $68 billion in gross debt and intends to reduce debt over time.

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

Capital and exploration expenditures (Capex) represents the combined total of additions at cost to property, plant and equipment, and exploration expenses on a before-tax basis from the Consolidated Statement of Income. ExxonMobil's Capex includes its share of similar costs for equity companies. Capex excludes assets acquired in nonmonetary exchanges, the value of ExxonMobil shares used to acquire assets, and depreciation on the cost of exploration support equipment and facilities recorded to property, plant and equipment when acquired. While

ExxonMobil's management is responsible for all investments and elements of net income, particular focus is placed on managing the controllable aspects of this group of expenditures.

	2020			2019		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
			(millions of dollars)			
Upstream *(1)*	6,817	7,614	14,431	11,653	11,832	23,485
Downstream	2,344	1,877	4,221	2,353	2,018	4,371
Chemical	2,002	714	2,716	2,547	718	3,265
Other	6	—	6	27	—	27
Total	11,169	10,205	21,374	16,580	14,568	31,148

(1) Exploration expenses included.

Capex in 2020 was $21.4 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 is prioritizing opportunities to hold 2021 capital spending in a range of $16 billion to $19 billion. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $14.4 billion in 2020 was down 39 percent from 2019 in response to market conditions. Investments in 2020 included the U.S. Permian Basin and key development projects in Guyana. 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 67 percent of total proved reserves at year-end 2020, and has been over 60 percent for the last ten years.

Capital investments in the Downstream totaled $4.2 billion in 2020, a decrease of $0.2 billion from 2019, reflecting lower global project spending. Chemical capital expenditures of $2.7 billion, decreased $0.5 billion, representing reduced spend on growth projects.

TAXES

	2020	2019	2018
		(millions of dollars)	
Income taxes	(5,632)	5,282	9,532
Effective income tax rate	*17 %*	*34 %*	*37 %*
Total other taxes and duties	28,425	33,186	35,230
Total	22,793	38,468	44,762

2020

Total taxes on the Corporation's income statement were $22.8 billion in 2020, a decrease of $15.7 billion from 2019. Income tax expense, both current and deferred, was a benefit of $5.6 billion compared to $5.3 billion expense in 2019. The relative benefit is driven by asset impairments recorded in 2020. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 17 percent compared to 34 percent in the prior year due primarily to a change in mix of results in jurisdictions with varying tax rates. Total other taxes and duties of $28.4 billion in 2020 decreased $4.8 billion.

2019

Total taxes on the Corporation's income statement were $38.5 billion in 2019, a decrease of $6.3 billion from 2018. Income tax expense, both current and deferred, was $5.3 billion compared to $9.5 billion in 2018. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 34 percent compared to 37 percent in the prior year due primarily to the impact of the divestment of non-operated upstream assets in Norway. Total other taxes and duties of $33.2 billion in 2019 decreased $2.0 billion.

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2020	2019
	(millions of dollars)	
Capital expenditures	1,087	1,276
Other expenditures	3,389	3,969
Total	4,476	5,245

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 2020 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.5 billion, of which $3.4 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $4.9 billion in 2021 and 2022. Capital expenditures are expected to account for approximately 25 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 2020 for environmental liabilities were $263 million ($290 million in 2019) and the balance sheet reflects liabilities of $902 million as of December 31, 2020, and $835 million as of December 31, 2019.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2020	2019	2018
Crude oil and NGL ($ per barrel)	35.41	56.32	62.79
Natural gas ($ per thousand cubic feet)	2.01	3.05	3.87

(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 $475 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.

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. Refer to Note 18 for additional information on intersegment revenue.

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 assets are contributing to the Corporation's strategic objectives.

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 currency and interest rate derivatives, none of which are material to the Corporation's financial position as of December 31, 2020 and 2019, or results of operations for the years ended 2020, 2019 and 2018. 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 or cash flow. 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 long-term and short-term debt as required. Commercial paper is used to balance short-term liquidity requirements. 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 use of these 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. However, the global COVID-19 pandemic since early 2020 has brought unprecedented uncertainties to near-term economic outlooks. The Corporation continues to monitor 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.

RESTRUCTURING ACTIVITIES

During 2020, ExxonMobil conducted an extensive global review of staffing levels and subsequently commenced targeted workforce reductions within a number of countries to improve efficiency and reduce costs. The programs, which are expected to be substantially complete by the end of 2021, include both voluntary and involuntary employee separations and reductions in contractors.

In 2020 the Corporation recorded before-tax charges of $450 million ($349 million after tax), consisting primarily of employee separation costs, associated with announced workforce reduction programs in Europe, North America, and Australia. These costs are captured in “Selling, general and administrative expenses” on the Statement of Income and reported in the Corporate and financing segment. Before-tax cash outflows in 2020 associated with these activities were $47 million. The Corporation estimates additional charges of up to $200 million in 2021 related to planned workforce reduction programs with cash outflows ranging between $400 million and $600 million. Before-tax workforce reduction savings, including employees and contractors, are estimated to range between $1 billion and $2 billion per year after program completion when compared to 2019 levels.

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

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 oil and natural gas reserve volumes 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, development and production costs, 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 and Resources 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 67 percent of total proved reserves at year-end 2020 (including both consolidated and equity company reserves), an increase from 66 percent in 2019, 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 oil and natural gas price levels.

- 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.

Unit-of-Production Depreciation

Oil and natural gas reserve volumes 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.

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, profitability reviews and other periodic control processes 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 development 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 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 price or margin assumptions it uses for its capital investment decisions. To the extent those changes result in a significant reduction to its 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.

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 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.

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 ASC 932, and relies in part on the Corporation's planning and budgeting cycle. 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 including price differentials, refining and chemical margins, volumes, development and operating costs, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. 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. The assessment of fair value requires 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 value include estimates of acreage values and flowing production metrics from comparable market transactions, market-based estimates of historical cash flow multiples, and discounted cash flows. Inputs and assumptions used in discounted cash flow models include estimates of future production volumes, commodity prices which are consistent with the average of third-party industry experts and government agencies, drilling and development costs, and discount rates ranging from 6 percent to 8 percent which are reflective of the characteristics of the asset group.

Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the Corporation's future development plans, 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.

In 2020, the Corporation identified a number of situations where events or changes in circumstances indicated that the carrying value of certain long-lived assets may not be recoverable. Those situations primarily related to the annual review and approval of the Corporation's business and strategic plan. As part of the planning process, the Corporation assessed its full portfolio to prioritize assets with the highest future value potential within its broad range of available opportunities in order to optimize resources within current levels of debt and operating cash flow, as well as identify potential asset divestment candidates. This effort included a re-assessment of dry gas assets, primarily in North America, which previously had been included in the Corporation's future development plans. Under the plan as approved, the Corporation no longer plans to develop a significant portion of its dry gas portfolio, including a portion of its resources in the Appalachian, Rocky Mountains, Oklahoma, Texas, Louisiana, and Arkansas regions of the U.S. as well as resources in Western Canada and Argentina. The decision not to develop these assets resulted in non-cash, after-tax charges of $18.4 billion in Upstream to reduce the carrying value of those assets to fair value.

Other after-tax impairment charges in 2020 include $0.5 billion in Upstream and $0.3 billion in Downstream. As a result of these impairments, the Corporation expects lower 2021 depreciation and depletion charges in Upstream for most of these asset groups. However, largely due to the impact of lower 2020 proved reserves resulting from low prices, higher unit-of-production rates on certain assets in 2021 are expected to offset the effect of lower depreciation and depletion charges related to 2020 impairments. For further discussion on proved reserves, see Summary of Oil and Gas Reserves in the Disclosure of Reserves section in Item 2.

Factors which could put further assets at risk of impairment in the future include reductions in the Corporation's 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. For discussion of goodwill and equity company impairments, see Note 3 and Note 7 to the financial statements, respectively.

Asset Retirement Obligations

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

Suspended Exploratory Well Costs

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

Consolidations

The Consolidated Financial Statements include the accounts of 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 about 80 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 2020 was 5.3 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 9 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 $210 million before tax.

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

Litigation Contingencies

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

The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable, and the amount can be reasonably estimated. These accrued liabilities 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, 2020.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation’s internal control over financial reporting as of December 31, 2020, as stated in their report included in the Financial Section of this report.

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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

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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 sheet of Exxon Mobil Corporation and its subsidiaries (the "Corporation") as of December 31, 2020 and 2019, and the related consolidated statements of income, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2020, 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, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 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, 2020, 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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

The Impact of Proved Oil and Natural Gas Reserves on Upstream Property, Plant and Equipment, Net

As described in Notes 1, 9 and 18 to the consolidated financial statements, the Corporation's consolidated upstream property, plant and equipment (PP&E), net balance was $167.5 billion as of December 31, 2020, and the related depreciation and depletion expense for the year ended December 31, 2020 was $41.4 billion. Management uses the successful efforts method to account for its exploration and production activities. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. As disclosed by management, proved oil and natural gas reserve volumes are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. The estimation of proved oil and natural gas reserve volumes is an ongoing process based on technical evaluations, commercial and market assessments, and detailed analysis of well information such as flow rates and reservoir pressure declines, development and production costs, among other factors. As further disclosed by management, reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals, assisted by the Global Reserves and Resources Group (together "management's specialists").

The principal considerations for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on upstream PP&E, net is a critical audit matter are (i) the significant judgment by management, including the use of management's specialists, when developing the estimates of proved oil and natural gas reserve volumes, as the reserve volumes are based on engineering assumptions and methods, which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the data, methods, and assumptions used by management and its specialists in developing the estimates of oil and natural gas reserve volumes and the assumptions applied to the data related to future development costs and production costs, as applicable.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and natural gas reserve volumes. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved oil and natural gas reserve volumes. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists, and an evaluation of the specialists' findings. These procedures also included, among others, testing the completeness and accuracy of the data related to future development costs and production costs. Additionally, these procedures included evaluating whether the assumptions applied to the data related to future development costs and production costs were reasonable considering the past performance of the Company.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Impairment Assessment of Certain Upstream Property, Plant and Equipment, Net

As described in Notes 1, 9, and 18 to the consolidated financial statements, the Corporation’s consolidated upstream property, plant and equipment (PP&E), net balance was $167.5 billion as of December 31, 2020, and related impairment expense for the year ended December 31, 2020 was $25.3 billion. If events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, management 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 identifiable cash flows are largely independent of cash flows of other groups of assets. These evaluations make use of management’s assumptions of future capital allocations, crude oil and natural gas commodity prices including price differentials, volumes, development and operating costs, and foreign currency exchange rates. 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. Management’s estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities.

The principal considerations for our determination that performing procedures relating to the impairment assessment of certain upstream PP&E, net is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the estimates of future undiscounted cash flows and (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating management’s significant assumptions related to future crude oil and natural gas commodity prices, production volumes, and development costs, as applicable.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s upstream PP&E, net impairment assessment. These procedures also included, among others (i) testing management’s process for assessing the recoverability of carrying amounts of upstream PP&E, net; (ii) evaluating the appropriateness of the undiscounted cash flow models; (iii) testing the completeness and accuracy of underlying data used in the models; and (iv) evaluating the reasonableness of significant assumptions used by management related to future crude oil and natural gas commodity prices, production volumes, and development costs. Evaluating the reasonableness of management’s assumptions related to future crude oil and natural gas commodity prices involved comparing the assumption against observable market data. Evaluating future development costs involved evaluating the reasonableness of the assumptions as compared to the past performance of the Company. The work of management’s specialists was used in performing the procedures to evaluate the reasonableness of the proved oil and natural gas reserve volumes as stated in the Critical Audit Matter titled “Impact of Proved Oil and Natural Gas Reserves on Upstream Property, Plant and Equipment, Net” and the reasonableness of the future production volumes. As a basis for using this work, the specialists’ qualifications were understood and the Company’s relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists and an evaluation of the specialists’ findings.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 24, 2021

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

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2020	2019	2018
		(millions of dollars)		
Revenues and other income				
Sales and other operating revenue		178,574	255,583	279,332
Income from equity affiliates	7	1,732	5,441	7,355
Other income		1,196	3,914	3,525
Total revenues and other income		181,502	264,938	290,212
Costs and other deductions				
Crude oil and product purchases		94,007	143,801	156,172
Production and manufacturing expenses		30,431	36,826	36,682
Selling, general and administrative expenses		10,168	11,398	11,480
Depreciation and depletion (includes impairments)	3, 9	46,009	18,998	18,745
Exploration expenses, including dry holes		1,285	1,269	1,466
Non-service pension and postretirement benefit expense	17	1,205	1,235	1,285
Interest expense		1,158	830	766
Other taxes and duties	19	26,122	30,525	32,663
Total costs and other deductions		210,385	244,882	259,259
Income (Loss) before income taxes		(28,883)	20,056	30,953
Income tax expense (benefit)	19	(5,632)	5,282	9,532
Net income (loss) including noncontrolling interests		(23,251)	14,774	21,421
Net income (loss) attributable to noncontrolling interests		(811)	434	581
Net income (loss) attributable to ExxonMobil		(22,440)	14,340	20,840
Earnings (Loss) per common share *(dollars)*	12	(5.25)	3.36	4.88
Earnings (Loss) per common share - assuming dilution *(dollars)*	12	(5.25)	3.36	4.88

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2020	2019	2018
		(millions of dollars)	
Net income (loss) including noncontrolling interests	(23,251)	14,774	21,421
Other comprehensive income (loss) (net of income taxes)			
Foreign exchange translation adjustment	1,916	1,735	(5,077)
Adjustment for foreign exchange translation (gain)/loss included in net income	14	—	196
Postretirement benefits reserves adjustment (excluding amortization)	30	(2,092)	280
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	896	582	931
Total other comprehensive income (loss)	2,856	225	(3,670)
Comprehensive income (loss) including noncontrolling interests	(20,395)	14,999	17,751
Comprehensive income (loss) attributable to noncontrolling interests	(743)	588	174
Comprehensive income (loss) attributable to ExxonMobil	(19,652)	14,411	17,577

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	December 31, 2020	December 31, 2019
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		4,364	3,089
Notes and accounts receivable - net	6	20,581	26,966
Inventories			
Crude oil, products and merchandise	3	14,169	14,010
Materials and supplies		4,681	4,518
Other current assets		1,098	1,469
Total current assets		44,893	50,052
Investments, advances and long-term receivables	8	43,515	43,164
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	227,553	253,018
Other assets, including intangibles - net		16,789	16,363
Total assets		332,750	362,597
Liabilities			
Current liabilities			
Notes and loans payable	6	20,458	20,578
Accounts payable and accrued liabilities	6	35,221	41,831
Income taxes payable		684	1,580
Total current liabilities		56,363	63,989
Long-term debt	14	47,182	26,342
Postretirement benefits reserves	17	22,415	22,304
Deferred income tax liabilities	19	18,165	25,620
Long-term obligations to equity companies		3,253	3,988
Other long-term obligations		21,242	21,416
Total liabilities		168,620	163,659
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		15,688	15,637
Earnings reinvested		383,943	421,341
Accumulated other comprehensive income		(16,705)	(19,493)
Common stock held in treasury (3,786 million shares in 2020 and 3,785 million shares in 2019)		(225,776)	(225,835)
ExxonMobil share of equity		157,150	191,650
Noncontrolling interests		6,980	7,288
Total equity		164,130	198,938
Total liabilities and equity		332,750	362,597

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2020	2019	2018
		(millions of dollars)		
Cash flows from operating activities				
Net income (loss) including noncontrolling interests		(23,251)	14,774	21,421
Adjustments for noncash transactions				
Depreciation and depletion (includes impairments)	3, 9	46,009	18,998	18,745
Deferred income tax charges/(credits)	19	(8,856)	(944)	(60)
Postretirement benefits expense in excess of/(less than) net payments		498	109	1,070
Other long-term obligation provisions in excess of/(less than) payments		(1,269)	(3,038)	(68)
Dividends received greater than/(less than) equity in current earnings of equity companies		979	(936)	(1,684)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		5,384	(2,640)	(545)
- Inventories		(315)	72	(3,107)
- Other current assets		420	(234)	(25)
Increase/(reduction) - Accounts and other payables		(7,142)	3,725	2,321
Net (gain)/loss on asset sales	5	4	(1,710)	(1,993)
All other items - net		2,207	1,540	(61)
Net cash provided by operating activities		14,668	29,716	36,014
Cash flows from investing activities				
Additions to property, plant and equipment		(17,282)	(24,361)	(19,574)
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments		999	3,692	4,123
Additional investments and advances		(4,857)	(3,905)	(1,981)
Other investing activities including collection of advances		2,681	1,490	986
Net cash used in investing activities		(18,459)	(23,084)	(16,446)
Cash flows from financing activities				
Additions to long-term debt		23,186	7,052	46
Reductions in long-term debt		(8)	(1)	—
Reductions in short-term debt		(1,703)	(4,043)	(4,752)
Additions/(reductions) in commercial paper, and debt with three months or less maturity	5	(1,334)	5,654	(219)
Contingent consideration payments		(21)	—	—
Cash dividends to ExxonMobil shareholders		(14,865)	(14,652)	(13,798)
Cash dividends to noncontrolling interests		(188)	(192)	(243)
Changes in noncontrolling interests		623	158	146
Common stock acquired		(405)	(594)	(626)
Net cash provided by (used in) financing activities		5,285	(6,618)	(19,446)
Effects of exchange rate changes on cash		(219)	33	(257)
Increase/(decrease) in cash and cash equivalents		1,275	47	(135)
Cash and cash equivalents at beginning of year		3,089	3,042	3,177
Cash and cash equivalents at end of year		4,364	3,089	3,042

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	Total Equity
				(millions of dollars)			
Balance as of December 31, 2017	14,656	414,540	(16,262)	(225,246)	187,688	6,812	194,500
Amortization of stock-based awards	758	—	—	—	758	—	758
Other	(156)	—	—	—	(156)	436	280
Net income (loss) for the year	—	20,840	—	—	20,840	581	21,421
Dividends - common shares	—	(13,798)	—	—	(13,798)	(243)	(14,041)
Cumulative effect of accounting change	—	71	(39)	—	32	15	47
Other comprehensive income	—	—	(3,263)	—	(3,263)	(407)	(3,670)
Acquisitions, at cost	—	—	—	(626)	(626)	(460)	(1,086)
Dispositions	—	—	—	319	319	—	319
Balance as of December 31, 2018	15,258	421,653	(19,564)	(225,553)	191,794	6,734	198,528
Amortization of stock-based awards	697	—	—	—	697	—	697
Other	(318)	—	—	—	(318)	489	171
Net income (loss) for the year	—	14,340	—	—	14,340	434	14,774
Dividends - common shares	—	(14,652)	—	—	(14,652)	(192)	(14,844)
Other comprehensive income	—	—	71	—	71	154	225
Acquisitions, at cost	—	—	—	(594)	(594)	(331)	(925)
Dispositions	—	—	—	312	312	—	312
Balance as of December 31, 2019	15,637	421,341	(19,493)	(225,835)	191,650	7,288	198,938
Amortization of stock-based awards	696	—	—	—	696	—	696
Other	(645)	—	—	—	(645)	692	47
Net income (loss) for the year	—	(22,440)	—	—	(22,440)	(811)	(23,251)
Dividends - common shares	—	(14,865)	—	—	(14,865)	(188)	(15,053)
Cumulative effect of accounting change	—	(93)	—	—	(93)	(1)	(94)
Other comprehensive income	—	—	2,788	—	2,788	68	2,856
Acquisitions, at cost	—	—	—	(405)	(405)	(68)	(473)
Dispositions	—	—	—	464	464	—	464
Balance as of December 31, 2020	15,688	383,943	(16,705)	(225,776)	157,150	6,980	164,130

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2017	8,019	(3,780)	4,239
Acquisitions	—	(8)	(8)
Dispositions	—	6	6
Balance as of December 31, 2018	8,019	(3,782)	4,237
Acquisitions	—	(8)	(8)
Dispositions	—	5	5
Balance as of December 31, 2019	8,019	(3,785)	4,234
Acquisitions	—	(8)	(8)
Dispositions	—	7	7
Balance as of December 31, 2020	8,019	(3,786)	4,233

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

The Corporation's principal business 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.

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years' data has been reclassified in certain cases to conform to the 2020 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation and Accounting for Investments

The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses. Amounts representing the Corporation's interest in entities that it does not control, but over which it exercises significant influence, are included in "Investments, advances and long-term receivables". The Corporation's share of the net income of these companies is included in the Consolidated Statement of Income caption "Income from equity affiliates".

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

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

Investments in equity securities other than consolidated subsidiaries and equity method investments are measured at fair value with changes in fair value recognized in net income. The Corporation uses the modified approach for equity securities that do not have a readily determinable fair value. This modified approach measures investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions in a similar investment of the same issuer.

The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in "Accumulated other comprehensive income".

Revenue Recognition

The Corporation generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments to reflect market conditions. Revenue is recognized at the amount the Corporation expects to receive when the customer has taken control, which is typically when title transfers and the customer has assumed the risks and rewards of ownership. The prices of certain sales are based on price indices that are sometimes not available until the next period. In such cases, estimated realizations are accrued when the sale is recognized, and are finalized when the price is available. Such adjustments to revenue from performance obligations satisfied in previous periods are not significant. Payment for revenue transactions is typically due within 30 days. Future volume delivery obligations that are unsatisfied at the end of the period are expected to be fulfilled through ordinary production or purchases. These performance obligations are based on market prices at the time of the transaction and are fully constrained due to market price volatility.

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

"Sales and other operating revenue" and "Notes and accounts receivable" primarily arise from contracts with customers. Long-term receivables are primarily from non-customers. Contract assets are mainly from marketing assistance programs and are not significant. Contract liabilities are mainly customer prepayments and accruals of expected volume discounts and are not significant.

Income and Other Taxes

The Corporation excludes from the Consolidated Statement of Income certain sales and value-added taxes imposed on and concurrent with revenue-producing transactions with customers and collected on behalf of governmental authorities. Similar taxes, for which the Corporation is not considered to be an agent for the government, are reported on a gross basis (included in both "Sales and other operating revenue" and "Other taxes and duties").

The Corporation accounts for U.S. tax on global intangible low-taxed income as an income tax expense in the period in which it is incurred.

Derivative Instruments

The Corporation may use derivative instruments for trading purposes and to offset exposures associated with commodity prices, foreign currency exchange rates and interest rates that arise from existing assets, liabilities, firm commitments and forecasted transactions. All derivative instruments, except those designated as normal purchase and normal sale, are recorded at fair value. Derivative assets and liabilities with the same counterparty are netted if the right of offset exists and certain other criteria are met. Collateral payables or receivables are netted against derivative assets and derivative liabilities, respectively.

Recognition and classification of the gain or loss that results from adjusting a derivative to fair value depends on the purpose for the derivative. All gains and losses from derivative instruments for which the Corporation does not apply hedge accounting are immediately recognized in earnings. The Corporation may designate derivatives as fair value or cash flow hedges. For fair value hedges, the gain or loss from derivative instruments and the offsetting gain or loss from the hedged item are recognized in earnings. For cash flow hedges, the gain or loss from the derivative instrument is initially reported as a component of other comprehensive income and subsequently reclassified into earnings in the period that the forecasted transaction affects earnings.

Fair Value

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

Inventories

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

Property, Plant and Equipment

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

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

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

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.

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

Impairment Assessment. The Corporation tests assets or groups of assets for recoverability 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 analysis, profitability reviews and other periodic control processes 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 development 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 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 price or margin assumptions it uses for its capital investment decisions. To the extent those changes result in a significant reduction to its 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.

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 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.

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 ASC 932, and relies in part on the Corporation’s planning and budgeting cycle. 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 including price differentials, refining and chemical margins, volumes, development and operating costs, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management’s estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. 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.

Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the Corporation's future development plans, the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

Other. Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any substantial obligation for future performance by the Corporation. Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

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

Environmental Liabilities

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

Foreign Currency Translation

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

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

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

2. Accounting Changes

Effective January 1, 2020, the Corporation adopted the Financial Accounting Standards Board's update, *Financial Instruments – Credit Losses (Topic 326)*, as amended. The standard requires a valuation allowance for credit losses be recognized for certain financial assets that reflects the current expected credit loss over the asset's contractual life. The valuation allowance considers the risk of loss, even if remote, and considers past events, current conditions and reasonable and supportable forecasts. The standard requires this expected loss methodology for trade receivables, certain other financial assets and off-balance sheet credit exposures. The cumulative effect adjustment related to the adoption of this standard reduced ExxonMobil's share of equity by $93 million.

The Corporation is exposed to credit losses primarily through sales of petroleum products, crude oil, natural gas liquids and natural gas, as well as loans to equity companies and joint venture receivables. A counterparty's ability to pay is assessed through a credit review process that considers payment terms, the counterparty's established credit rating or the Corporation's assessment of the counterparty's credit worthiness, contract terms, country of operation, and other risks. The Corporation can require prepayment or collateral to mitigate certain credit risks.

The Corporation groups financial assets into portfolios that share similar risk characteristics for purposes of determining the allowance for credit losses and assesses if a significant change in the risk of credit loss has occurred. Among the quantitative and qualitative factors considered are historical financial data, current conditions, industry and country risk, current credit ratings and the quality of third-party guarantees secured from the counterparty. Financial assets are written off in whole, or in part, when practical recovery efforts have been exhausted and no reasonable expectation of recovery exists. Subsequent recoveries of amounts previously written off are recognized in earnings. The Corporation manages receivable portfolios using past due balances as a key credit quality indicator.

The Corporation recognizes a credit allowance for off-balance sheet credit exposures as a liability on the balance sheet, separate from the allowance for credit losses related to recognized financial assets. Among these exposures are unfunded loans to equity companies and financial guarantees that cannot be cancelled unilaterally by the Corporation.

	Allowance for Current Expected Credit Losses				
	Notes and Accounts Receivable				
	Trade	Other	Advances and Long-Term Receivables	Liabilities for Off-Balance Sheet Assets	Total
	(millions of dollars)				
Balance at December 31, 2019	34	56	413	—	503
Cumulative effect of accounting change	52	6	39	12	109
Current period provision	9	15	(9)	(1)	14
Write-offs charged against the allowance	(2)	(3)	—	—	(5)
Other	2	(3)	3	—	2
Balance at December 31, 2020	95	71	446	11	623
Balance at December 31, 2020					
Financial Assets subject to credit losses standard - net	16,250	1,962	9,447		

3. Miscellaneous Financial Information

Research and development expenses totaled $1,016 million in 2020, $1,214 million in 2019, and $1,116 million in 2018.

Net income included before-tax aggregate foreign exchange transaction losses of $24 million, $104 million and $138 million in 2020, 2019 and 2018, respectively.

In 2020, 2019, and 2018, net income included gains of $41 million, $523 million, and $107 million, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $5.4 billion and $9.7 billion at December 31, 2020, and 2019, respectively.

Crude oil, products and merchandise as of year-end 2020 and 2019 consist of the following:

	Dec 31, 2020	Dec 31, 2019
	(millions of dollars)	
Crude oil	5,354	5,111
Petroleum products	5,138	5,281
Chemical products	3,023	3,240
Gas/other	654	378
Total	14,169	14,010

Mainly as a result of declines in prices for crude oil, natural gas and petroleum products in 2020 and a significant decline in its market capitalization at the end of the first quarter, the Corporation recognized before-tax goodwill impairment charges of $611 million in Upstream, Downstream, and Chemical reporting units. Fair value of the goodwill reporting units primarily reflected market-based estimates of historical EBITDA multiples at the end of the first quarter. Charges related to goodwill impairments are included in “Depreciation and depletion” on the Statement of Income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	Cumulative Foreign Exchange Translation Adjustment	Postretirement Benefits Reserves Adjustment	Total
		(millions of dollars)	
Balance as of December 31, 2017	(9,482)	(6,780)	(16,262)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(4,595)	201	(4,394)
Amounts reclassified from accumulated other comprehensive income	196	896	1,092
Total change in accumulated other comprehensive income	(4,399)	1,097	(3,302)
Balance as of December 31, 2018	(13,881)	(5,683)	(19,564)
Current period change excluding amounts reclassified from accumulated other comprehensive income	1,435	(1,927)	(492)
Amounts reclassified from accumulated other comprehensive income	—	563	563
Total change in accumulated other comprehensive income	1,435	(1,364)	71
Balance as of December 31, 2019	(12,446)	(7,047)	(19,493)

(1) Cumulative Foreign Exchange Translation Adjustment includes net investment hedge gain/(loss) of $ (355) million, net of taxes.

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/ (Expense)	**2020**	**2019**	**2018**
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	(14)	—	(196)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs (Statement of Income line: Non-service pension and postretirement benefit expense)	(1,158)	(751)	(1,208)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	**2020**	**2019**	**2018**
		(millions of dollars)	
Foreign exchange translation adjustment	118	88	32
Postretirement benefits reserves adjustment (excluding amortization)	109	719	(193)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(262)	(169)	(277)
Total	(35)	638	(438)

5. Cash Flow Information

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

For 2020, the "Depreciation and depletion" and "Deferred income tax charges/(credits)" on the Consolidated Statement of Cash Flows includes impacts from asset impairments, primarily in Upstream.

For 2019, the "Net (gain)/loss on asset sales" on the Consolidated Statement of Cash Flows includes before-tax amounts from the sale of non-operated upstream assets in Norway and upstream asset transactions in the U.S. The Norway assets were sold for $4.5 billion, resulting in a gain of $3.7 billion and cash proceeds of $3.1 billion in 2019. For 2018, the number includes before-tax amounts from the sale of service stations in Germany, the divestment of the Augusta refinery in Italy, and the sale of an undeveloped upstream property in Australia. These net gains are reported in "Other income" on the Consolidated Statement of Income.

In 2020, the "Additions/(reductions) in commercial paper, and debt with three months or less maturity" on the Consolidated Statement of Cash Flows includes a net $8.4 billion addition of commercial paper with maturity over three months. The gross amount issued was $35.4 billion, while the gross amount repaid was $27.0 billion. In 2019, the number includes a net $4.6 billion addition of commercial paper with maturity over three months. The gross amount issued was $18.9 billion, while the gross amount repaid was $14.3 billion. In 2018, the number includes a net $275 million addition of commercial paper with maturity over three months. The gross amount issued was $4.0 billion, while the gross amount repaid was $3.8 billion.

	2020	2019	2018
		(millions of dollars)	
Income taxes paid	2,428	7,018	9,294
Cash interest paid			
Included in cash flows from operating activities	786	560	303
Capitalized, included in cash flows from investing activities	665	731	652
Total cash interest paid	1,451	1,291	955

6. Additional Working Capital Information

	Dec 31, 2020	Dec 31, 2019
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $96 million and $34 million	16,339	21,100
Other, less reserves of $378 million and $371 million	4,242	5,866
Total	20,581	26,966
Notes and loans payable		
Bank loans	222	316
Commercial paper	17,306	18,561
Long-term debt due within one year	2,930	1,701
Total	20,458	20,578
Accounts payable and accrued liabilities		
Trade payables	17,499	24,694
Payables to equity companies	6,476	6,825
Accrued taxes other than income taxes	3,408	3,301
Other	7,838	7,011
Total	35,221	41,831

The Corporation has short-term committed lines of credit of $11.3 billion which were unused as of December 31, 2020. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 0.2 percent and 1.7 percent at December 31, 2020, and 2019, respectively.

7. Equity Company Information

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

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 11 percent, 13 percent and 14 percent in the years 2020, 2019 and 2018, respectively.

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

Impairments related to U.S. upstream equity investments of $600 million are included in "Income from equity affiliates" on the Consolidated Statement of Income.

	2020		2019		2018	
Equity Company Financial Summary	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**
			(millions of dollars)			
Total revenues	69,954	21,282	102,365	31,240	112,938	34,539
Income before income taxes	12,743	2,830	29,424	7,927	37,203	10,482
Income taxes	4,333	870	9,725	2,500	11,568	3,151
Income from equity affiliates	8,410	1,960	19,699	5,427	25,635	7,331
Current assets	33,419	11,969	36,035	12,661	38,670	13,394
Long-term assets	150,358	41,457	143,321	40,001	128,830	35,970
Total assets	183,777	53,426	179,356	52,662	167,500	49,364
Current liabilities	18,827	5,245	24,583	6,939	27,324	7,606
Long-term liabilities	66,053	19,927	61,022	18,158	56,913	17,109
Net assets	98,897	28,254	93,751	27,565	83,263	24,649

A list of significant equity companies as of December 31, 2020, together with the Corporation’s percentage ownership interest, is detailed below:

	Percenta Ownersh Interes
Upstream	
Aera Energy LLC	48
Barzan Gas Company Limited	7
BEB Erdgas und Erdoel GmbH & Co. KG	50
Cameroon Oil Transportation Company S.A.	41
Caspian Pipeline Consortium - Kazakhstan	8
CORAL FLNG, S.A.	25
Cross Timbers Energy, LLC	50
Golden Pass LNG Terminal LLC	30
Golden Pass Pipeline LLC	30
Marine Well Containment Company LLC	10
Mozambique Rovuma Venture, S.p.A.	36
Nederlandse Aardolie Maatschappij B.V.	50
Papua New Guinea Liquefied Natural Gas Global Company LDC	33
Permian Highway Pipeline LLC	20
Qatar Liquefied Gas Company Limited	10
Qatar Liquefied Gas Company Limited (2)	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited (II)	31
Ras Laffan Liquefied Natural Gas Company Limited (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	71
Downstream	
Alberta Products Pipe Line Ltd.	45
Fujian Refining & Petrochemical Co. Ltd.	25
Permian Express Partners LLC	12
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Gulf Coast Growth Ventures LLC	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec 31, 2020	Dec 31, 2019
	(millions of dollars)	
Equity method company investments and advances		
Investments	29,772	29,291
Advances, net of allowances of $31 million in 2020	8,812	8,542
Total equity method company investments and advances	38,584	37,833
Equity securities carried at fair value and other investments at adjusted cost basis	143	190
Long-term receivables and miscellaneous, net of reserves of $6,115 million and $5,643 million	4,788	5,141
Total	43,515	43,164

9. Property, Plant and Equipment and Asset Retirement Obligations

	December 31, 2020		December 31, 2019	
Property, Plant and Equipment	Cost	Net	Cost	Net
	(millions of dollars)			
Upstream	386,614	167,472	376,041	196,767
Downstream	57,922	27,716	52,527	24,506
Chemical	42,868	21,924	40,788	21,260
Other	17,918	10,441	17,346	10,485
Total	505,322	227,553	486,702	253,018

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 ASC 932, and relies in part on the Corporation’s planning and budgeting cycle. In 2020, the Corporation identified a number of situations where events or changes in circumstances indicated that the carrying value of certain long-lived assets may not be recoverable. Those situations primarily related to the annual review and approval of the Corporation's business and strategic plan. As part of the planning process, the Corporation assessed its full portfolio to prioritize assets with the highest future value potential within its broad range of available opportunities in order to optimize resources within current levels of debt and operating cash flow, as well as identify potential asset divestment candidates. This effort included a re-assessment of dry gas assets, primarily in North America, which previously had been included in the Corporation’s future development plans. Under the plan as approved, the Corporation no longer plans to develop a significant portion of its dry gas portfolio, including a portion of its resources in the Appalachian, Rocky Mountains, Oklahoma, Texas, Louisiana, and Arkansas regions of the U.S., as well as resources in Western Canada and Argentina. The decision not to develop these assets resulted in non-cash, before-tax charges of $24.4 billion in Upstream to reduce the carrying value of those assets to fair value. Other before-tax impairment charges in 2020 included $0.9 billion in Upstream, $0.5 billion in Downstream, and $0.1 billion in Chemical. Impairment charges are primarily recognized in the lines “Depreciation and depletion” and “Exploration expenses, including dry holes” on the Consolidated Statement of Income.

The assessment of fair value requires 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 value include estimates of acreage values and flowing production metrics from comparable market transactions, market-based estimates of historical cash flow multiples, and discounted cash flows. Inputs and assumptions used in discounted cash flow models include estimates of future production volumes, commodity prices which were consistent with the average of third-party industry experts and government agencies, drilling and development costs, and discount rates ranging from 6 percent to 8 percent which are reflective of the characteristics of the asset group.

Factors which could put further assets at risk of impairment in the future include reductions in the Corporation’s 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. In 2019 and 2018, the before-tax impairment charges were $0.1 billion and $0.7 billion, respectively.

Accumulated depreciation and depletion totaled $277,769 million at the end of 2020 and $233,684 million at the end of 2019. Interest capitalized in 2020, 2019 and 2018 was $665 million, $731 million and $652 million, respectively.

Asset Retirement Obligations

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

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

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

	2020	2019	2018
		(millions of dollars)	
Balance at January 1	11,280	12,103	12,705
Accretion expense and other provisions	584	649	681
Reduction due to property sales	(77)	(1,085)	(333)
Payments made	(669)	(827)	(600)
Liabilities incurred	26	89	46
Foreign currency translation	239	84	(481)
Revisions	(136)	267	85
Balance at December 31	11,247	11,280	12,103

The long-term Asset Retirement Obligations were $10,558 million and $10,279 million at December 31, 2020, and 2019, respectively, and are included in “Other long-term obligations.”

10. Accounting for Suspended Exploratory Well Costs

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

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

Change in capitalized suspended exploratory well costs:

	2020	2019	2018
		(millions of dollars)	
Balance beginning at January 1	4,613	4,160	3,700
Additions pending the determination of proved reserves	208	532	564
Charged to expense	(318)	(46)	(7)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(174)	(37)	(48)
Divestments/Other	53	4	(49)
Ending balance at December 31	4,382	4,613	4,160
Ending balance attributed to equity companies included above	306	306	306

Period end capitalized suspended exploratory well costs:

	2020	2019	2018
		(millions of dollars)	
Capitalized for a period of one year or less	208	532	564
Capitalized for a period of between one and five years	1,828	2,206	2,028
Capitalized for a period of between five and ten years	1,932	1,411	1,150
Capitalized for a period of greater than ten years	414	464	418
Capitalized for a period greater than one year - subtotal	4,174	4,081	3,596
Total	4,382	4,613	4,160

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a breakdown of the number of projects with only exploratory well costs capitalized for a period of one year or less and those that have had exploratory well costs capitalized for a period greater than one year.

	2020	2019	2018
Number of projects that only have exploratory well costs capitalized for a period of one year or less	3	4	6
Number of projects that have exploratory well costs capitalized for a period greater than one year	34	46	52
Total	37	50	58

Of the 34 projects that have exploratory well costs capitalized for a period greater than one year as of December 31, 2020, 13 projects have drilling in the preceding year or exploratory activity planned in the next two years, while the remaining 21 projects are those with completed exploratory activity progressing toward development.

The table below provides additional detail for those 21 projects, which total $3,181 million.

Country/Project	Dec. 31, 2020	Years Wells Drilled / Acquired	Comment
(millions of dollars)			
Angola			
– Kaombo Split Hub Phase 2	10	2006	Evaluating development plan to tie into planned production facilities.
Argentina			
– La Invernada	72	2014	Evaluating development plan to tie into planned infrastructure.
Australia			
– Gorgon Area Ullage	347	1994 -2015	Evaluating development plans to tie into existing LNG facilities.
Brazil			
– Bacalhau Phase 1	284	2018	Continuing discussions with the government regarding development plan.
Canada			
– Hibernia North	26	2019	Awaiting capacity in existing/planned infrastructure.
Iraq			
– Kurdistan Pirmam	109	2015	Evaluating commercialization alternatives, while waiting for government approval to enter Gas Holding Period.
Kazakhstan			
– Kairan	53	2004 -2007	Evaluating commercialization and field development alternatives, while continuing discussions with the government regarding the development plan.
Mozambique			
– Rovuma LNG Future Non-Straddling Train	120	2017	Evaluating/progressing development plan to tie into planned LNG facilities.
– Rovuma LNG Phase 1	150	2017	Progressing development plan to tie into planned LNG facilities.
– Rovuma LNG Unitized Trains	35	2017	Evaluating/progressing development plan to tie into planned LNG facilities.
Nigeria			
– Bonga North	34	2004 -2009	Evaluating/progressing development plan for tieback to existing/planned infrastructure.
– Bonga SW	3	2001	Evaluating/progressing development plan for tieback to existing/planned infrastructure.
– Bosi	79	2002 -2006	Development activity under way, while continuing discussions with the government regarding development plan.
– Owowo	67	2009 -2016	Evaluating development plan for tieback to existing production facilities.
– Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
– Ukot SW	41	2014	Evaluating development plan for tieback to existing production facilities.
Papua New Guinea			
– Papua LNG	246	2017	Evaluating/progressing development plans.
– P'nyang	116	2012 -2018	Evaluating/progressing development plans.
Romania			
– Neptun Deep	536	2012 -2016	Continuing discussions with the government regarding development plan.
Tanzania			
– Tanzania Block 2	525	2012 -2015	Evaluating development alternatives, while continuing

11. Leases

The Corporation and its consolidated affiliates generally purchase the property, plant and equipment used in operations, but there are situations where assets are leased, primarily for drilling equipment, tankers, office buildings, railcars, and other moveable equipment. Right of use assets and lease liabilities are established on the balance sheet for leases with an expected term greater than one year by discounting the amounts fixed in the lease agreement for the duration of the lease which is reasonably certain, considering the probability of exercising any early termination and extension options. The portion of the fixed payment related to service costs for drilling equipment, tankers and finance leases is excluded from the calculation of right of use assets and lease liabilities. Generally, assets are leased only for a portion of their useful lives, and are accounted for as operating leases. In limited situations assets are leased for nearly all of their useful lives, and are accounted for as finance leases.

Variable payments under these lease agreements are not significant. Residual value guarantees, restrictions, or covenants related to leases, and transactions with related parties are also not significant. In general, leases are capitalized using the incremental borrowing rate of the leasing affiliate. The Corporation's activities as a lessor are not significant.

	Operating Leases			
	Drilling Rigs and Related Equipment	Other	Total	Finance Leases
		(millions of dollars)		
Lease Cost		2020		
Operating lease cost	297	1,256	1,553	
Short-term and other (net of sublease rental income)	530	1,083	1,613	
Amortization of right of use assets				143
Interest on lease liabilities				169
Total	827	2,339	3,166	312

	Operating Leases			
	Drilling Rigs and Related Equipment	Other	Total	Finance Leases
		(millions of dollars)		
Lease Cost		2019		
Operating lease cost	238	1,196	1,434	
Short-term and other (net of sublease rental income)	926	1,116	2,042	
Amortization of right of use assets				121
Interest on lease liabilities				133
Total	1,164	2,312	3,476	254

	Operating Leases			
	Drilling Rigs and Related Equipment	Other	Total	Finance Leases
	(millions of dollars)			
Balance Sheet	December 31, 2020			
Right of use assets				
Included in Other assets, including intangibles - net	834	5,244	6,078	
Included in Property, plant and equipment - net				2,188
Total right of use assets	834	5,244	6,078	2,188
Lease liability due within one year				
Included in Accounts payable and accrued liabilities	243	925	1,168	4
Included in Notes and loans payable				102
Long-term lease liability				
Included in Other long-term obligations	589	3,405	3,994	
Included in Long-term debt				1,680
Included in Long-term obligations to equity companies				135
Total lease liability	832	4,330	5,162	1,921
Weighted average remaining lease term - years	5	12	11	20
Weighted average discount rate - percent	2.2 %	3.0 %	2.9 %	8.9 %

Balance Sheet	Operating Leases: Drilling Rigs and Related Equipment	Operating Leases: Other	Operating Leases: Total	Finance Leases
	(millions of dollars)			
	December 31, 2019			
Right of use assets				
Included in Other assets, including intangibles - net	572	6,061	6,633	
Included in Property, plant and equipment - net				1,997
Total right of use assets	572	6,061	6,633	1,997
Lease liability due within one year				
Included in Accounts payable and accrued liabilities	221	990	1,211	15
Included in Notes and loans payable				84
Long-term lease liability				
Included in Other long-term obligations	330	4,152	4,482	
Included in Long-term debt				1,670
Included in Long-term obligations to equity companies				139
Total lease liability	551	5,142	5,693	1,908
Weighted average remaining lease term - years	4	11	10	20
Weighted average discount rate - percent	3.1 %	3.2 %	3.2 %	9.7 %

Maturity Analysis of Lease Liabilities	Operating Leases: Drilling Rigs and Related Equipment	Operating Leases: Other	Operating Leases: Total	Finance Leases
	(millions of dollars)			
	December 31, 2020			
2021	259	1,031	1,290	268
2022	256	817	1,073	259
2023	97	482	579	252
2024	71	387	458	247
2025	71	342	413	240
2026 and beyond	124	2,157	2,281	2,544
Total lease payments	878	5,216	6,094	3,810
Discount to present value	(46)	(886)	(932)	(1,889)
Total lease liability	832	4,330	5,162	1,921

In addition to the lease liabilities in the table immediately above, at December 31, 2020, undiscounted commitments for leases not yet commenced totaled $445 million for operating leases and $4,109 million for finance leases. The finance leases relate to floating production storage and offloading vessels, LNG transportation vessels, and a long-term hydrogen purchase agreement. The underlying assets for these finance leases were primarily designed by, and are being constructed by, the lessors.

Other Information	Operating Leases: Drilling Rigs and Related Equipment	Operating Leases: Other	Operating Leases: Total	Finance Leases
	(millions of dollars)			
	2020			
Cash paid for amounts included in the measurement of lease liabilities				
Cash flows from operating activities		1,159	1,159	31
Cash flows from investing activities	283		283	
Cash flows from financing activities				94
Noncash right of use assets recorded in exchange for lease liabilities	552	183	735	108

Other Information	Operating Leases: Drilling Rigs and Related Equipment	Operating Leases: Other	Operating Leases: Total	Finance Leases
	(millions of dollars) 2019			
Cash paid for amounts included in the measurement of lease liabilities				
Cash flows from operating activities		1,116	1,116	54
Cash flows from investing activities	258		258	
Cash flows from financing activities				177
Noncash right of use assets recorded for lease liabilities				
For January 1 adoption of ASC 842	445	2,818	3,263	
In exchange for lease liabilities during the period	350	3,313	3,663	422

Disclosures under the previous lease standard (ASC 840)

Net rental cost incurred under both cancelable and noncancelable operating leases was $2,715 million in 2018.

12. Earnings Per Share

Earnings per common share	**2020**	**2019**	**2018**
Net income (loss) attributable to ExxonMobil *(millions of dollars)*	(22,440)	14,340	20,840
Weighted average number of common shares outstanding *(millions of shares)*	4,271	4,270	4,270
Earnings (Loss) per common share *(dollars)* *(1)*	(5.25)	3.36	4.88
Dividends paid per common share *(dollars)*	3.48	3.43	3.23

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

13. Financial Instruments and Derivatives

Financial Instruments. The estimated fair value of financial instruments at December 31, 2020 and December 31, 2019, and the related hierarchy level for the fair value measurement is as follows:

	At December 31, 2020							
	(millions of dollars)							
	Fair Value							
	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets *(1)*	1,247	194	—	1,441	(1,282)	(6)	—	153
Advances to/receivables from equity companies *(2)(6)*	—	3,275	5,904	9,179	—	—	(367)	8,812
Other long-term financial assets *(3)*	1,235	—	944	2,179	—	—	125	2,304
Liabilities								
Derivative liabilities *(4)*	1,443	254	—	1,697	(1,282)	(202)	—	213
Long-term debt *(5)*	50,263	125	4	50,392	—	—	(4,890)	45,502
Long-term obligations to equity companies *(6)*	—	—	3,530	3,530	—	—	(277)	3,253
Other long-term financial liabilities *(7)*	—	—	964	964	—	—	44	1,008

	At December 31, 2019							
	(millions of dollars)							
	Fair Value							
	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets *(1)*	533	102	—	635	(463)	(70)	—	102
Advances to/receivables from equity companies *(2)(6)*	—	1,941	6,729	8,670	—	—	(128)	8,542
Other long-term financial assets *(3)*	1,145	—	974	2,119	—	—	44	2,163
Liabilities								
Derivative liabilities *(4)*	568	70	—	638	(463)	(105)	—	70
Long-term debt *(5)*	25,652	134	3	25,789	—	—	(1,117)	24,672
Long-term obligations to equity companies *(6)*	—	—	4,245	4,245	—	—	(257)	3,988
Other long-term financial liabilities *(7)*	—	—	1,042	1,042	—	—	16	1,058

(1) Included in the Balance Sheet lines: Notes and accounts receivable - net and Other assets, including intangibles - net

(2) Included in the Balance Sheet line: Investments, advances and long-term receivables

(3) Included in the Balance Sheet lines: Investments, advances and long term receivables and Other assets, including intangibles - net

(4) Included in the Balance Sheet lines: Accounts payable and accrued liabilities and Other long-term obligations

(5) Excluding finance lease obligations

(6) Advances to/receivables from equity companies and long-term obligations to equity companies are mainly designated as hierarchy level 3 inputs. The fair value is calculated by discounting the remaining obligations by a rate consistent with the credit quality and industry of the company.

(7) Included in the Balance Sheet line: Other long-term obligations. Includes contingent consideration related to a prior year acquisition where fair value is based on expected drilling activities and discount rates.

The increase in the estimated fair value and book value of long-term debt reflects the Corporation's issuance of $23 billion of long-term debt during 2020.

At December 31, 2020 and December 31, 2019, the Corporation had $504 million and $379 million of collateral under master netting arrangements not offset against the derivatives on the Consolidated Balance Sheet, primarily related to initial margin requirements.

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in 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. Commodity contracts held for trading purposes are presented in the Consolidated Statement of Income on a net basis in the line "Sales and other operating revenue". The Corporation's commodity derivatives are not accounted for under hedge accounting. At times, the Corporation also enters into currency and interest rate derivatives, none of which are material to the Corporation's financial position as of December 31, 2020 and 2019, or results of operations for the years ended 2020, 2019 and 2018.

Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

The net notional long/(short) position of derivative instruments at December 31, 2020, and December 31, 2019, was as follows:

	December 31, 2020		December 31, 2019
		(millions)	
Crude oil (barrels)	40		57
Petroleum products (barrels)	(46)		(38)
Natural gas (MMBTUs)	(500)		(165)

Realized and unrealized gains/(losses) on derivative instruments that were recognized in the Consolidated Statement of Income are included in the following lines on a before-tax basis:

	2020	2019	2018
		(millions of dollars)	
Sales and other operating revenue	404	(412)	130
Crude oil and product purchases	(407)	179	(120)
Total	(3)	(233)	10

14. Long-Term Debt

At December 31, 2020, long-term debt consisted of $41,026 million due in U.S. dollars and $6,156 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $2,930 million, which matures within one year and is included in current liabilities. The increase in the estimated fair value and book value of long-term debt reflects the Corporation's issuance of $23 billion of long-term debt during 2020. The amounts of long-term debt, excluding finance lease obligations, maturing in each of the four years after December 31, 2021, in millions of dollars, are: 2022 – $3,340; 2023 – $4,024; 2024 – $3,968; and 2025 – $4,672. At December 31, 2020, the Corporation had no unused long-term lines of credit.

The Corporation may use non-derivative financial instruments, such as its foreign currency-denominated debt, as hedges of its net investments in certain foreign subsidiaries. Under this method, the change in the carrying value of the financial instruments due to foreign exchange fluctuations is reported in accumulated other comprehensive income. As of December 31, 2020, the Corporation has designated its $5.5 billion of Euro-denominated long-term debt and related accrued interest as a net investment hedge of its European business. The net investment hedge is deemed to be perfectly effective.

Summarized long-term debt at year-end 2020 and 2019 are shown in the table below:

	Average Rate *(1)*	Dec 31, 2020	Dec 31, 2019
		(millions of dollars)	
Exxon Mobil Corporation *(2)*			
2.222% notes due 2021		—	2,500
2.397% notes due 2022		1,150	1,150
1.902% notes due 2022		750	750
Floating-rate notes due 2022 *(Issued 2015)*	1.118%	500	500
Floating-rate notes due 2022 *(Issued 2019)*	1.189%	750	750
1.571% notes due 2023		2,750	—
2.726% notes due 2023		1,250	1,250
3.176% notes due 2024		1,000	1,000
2.019% notes due 2024		1,000	1,000
2.709% notes due 2025		1,750	1,750
2.992% notes due 2025		2,807	—
3.043% notes due 2026		2,500	2,500
2.275% notes due 2026		1,000	1,000
3.294% notes due 2027		1,000	—
2.440% notes due 2029		1,250	1,250
3.482% notes due 2030		2,000	—
2.610% notes due 2030		2,000	—
2.995% notes due 2039		750	750
4.227% notes due 2040		2,091	—
3.567% notes due 2045		1,000	1,000
4.114% notes due 2046		2,500	2,500
3.095% notes due 2049		1,500	1,500
4.327% notes due 2050		2,750	—
3.452% notes due 2051		2,750	—
Exxon Mobil Corporation - Euro-denominated			
0.142% notes due 2024		1,841	—
0.524% notes due 2028		1,227	—
0.835% notes due 2032		1,227	—
1.408% notes due 2039		1,227	—
XTO Energy Inc. *(3)*			
6.100% senior notes due 2036		192	193
6.750% senior notes due 2037		294	296
6.375% senior notes due 2038		227	229
Mobil Corporation			
8.625% debentures due 2021		—	250
Industrial revenue bonds due 2022-2051	0.437%	2,461	2,461
Other U.S. dollar obligations		78	89
Other foreign currency obligations		61	64
Finance lease obligations	8.730%	1,680	1,670
Debt issuance costs		(131)	(60)
Total long-term debt		47,182	26,342

(1) Average effective interest rate for debt and average imputed interest rate for finance leases at December 31, 2020.
(2) Includes premiums of $148 million in 2020.
(3) Includes premiums of $87 million in 2020 and $92 million in 2019.

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock, and other forms of awards. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire, or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2020, remaining shares available for award under the 2003 Incentive Program were 71 million.

Restricted Stock and Restricted Stock Units. Awards totaling 8,681 thousand, 8,936 thousand, and 8,771 thousand of restricted (nonvested) common stock units were granted in 2020, 2019, and 2018, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years for the remaining 50 percent of the award, except that for awards granted prior to 2020 the vesting of the 10-year portion of the award is delayed until retirement if later than 10 years.

The Corporation has purchased shares in the open market and through negotiated transactions to offset shares or units settled in shares issued in conjunction with benefit plans and programs. The Corporation suspended its first quarter 2021 anti-dilutive share repurchase program due to current market uncertainty and intends to resume this program in the future as market conditions improve.

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2020.

	2020	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	39,628	84.50
Awards issued in 2020	9,030	68.95
Vested	(8,990)	86.84
Forfeited	(83)	82.04
Issued and outstanding at December 31	39,585	80.43

Value of restricted stock units	**2020**	**2019**	**2018**
Grant price *(dollars)*	41.15	68.77	77.66
Value at date of grant:		*(millions of dollars)*	
Units settled in stock	325	559	620
Units settled in cash	32	55	61
Total value	357	614	681

As of December 31, 2020, there was $1,356 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.2 years. The compensation cost charged against income for the restricted stock and restricted stock units was $672 million, $741 million, and $774 million for 2020, 2019, and 2018, respectively. The income tax benefit recognized in income related to this compensation expense was $51 million, $51 million, and $42 million for the same periods, respectively. The fair value of shares and units vested in 2020, 2019, and 2018 was $367 million, $647 million, and $722 million, respectively. Cash payments of $34 million, $56 million, and $61 million for vested restricted stock units settled in cash were made in 2020, 2019, and 2018, respectively.

16. Litigation and Other Contingencies

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

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2020, for guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management’s estimate of the maximum potential exposure.

	December 31, 2020		
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	986	124	1,110
Other	745	4,944	5,689
Total	1,731	5,068	6,799

(1) ExxonMobil share.

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

In accordance with a Venezuelan nationalization decree issued in February 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. The decree also required conversion of the Cerro Negro Project into a “mixed enterprise” and an increase in PdVSA’s or one of its affiliate’s ownership interest in the Project. ExxonMobil refused to accede to the terms proffered by the government, and on June 27, 2007, the government expropriated ExxonMobil’s 41.67 percent interest in the Cerro Negro Project.

ExxonMobil collected awards of $908 million in an arbitration against PdVSA under the rules of the International Chamber of Commerce in respect of an indemnity related to the Cerro Negro Project and $260 million in an arbitration for compensation due for the La Ceiba Project and for export curtailments at the Cerro Negro Project under rules of International Centre for Settlement of Investment Disputes (ICSID). An ICSID arbitration award relating to the Cerro Negro Project’s expropriation ($1.4 billion) was annulled based on a determination that a prior Tribunal failed to adequately explain why the cap on damages in the indemnity owed by PdVSA did not affect or limit the amount owed for the expropriation of the Cerro Negro Project. ExxonMobil filed a new claim seeking to restore the original award of damages for the Cerro Negro Project with ICSID on September 26, 2018.

The net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. Regardless, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition.

An affiliate of ExxonMobil is one of the Contractors under a Production Sharing Contract (PSC) with the Nigerian National Petroleum Corporation (NNPC) covering the Erha block located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the block and owns a 56.25 percent interest under the PSC. The Contractors are in dispute with NNPC regarding NNPC's lifting of crude oil in excess of its entitlement under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuja, Nigeria, under the Nigerian Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholding the Contractors' position in all material respects and awarding damages to the Contractors jointly in an amount of approximately $1.8 billion plus $234 million in accrued interest. The Contractors petitioned a Nigerian federal court for enforcement of the award, and NNPC petitioned the same court to have the award set aside. On May 22, 2012, the court set aside the award. The Contractors appealed that judgment to the Court of Appeal, Abuja Judicial Division. On July 22, 2016, the Court of Appeal upheld the decision of the lower court setting aside the award. On October 21, 2016, the Contractors appealed the decision to the Supreme Court of Nigeria. In June 2013, the Contractors filed a lawsuit against NNPC in the Nigerian federal high court in order to preserve their ability to seek enforcement of the PSC in the courts if necessary. Following dismissal by this court, the Contractors appealed to the Nigerian Court of Appeal in June 2016. In October 2014, the Contractors filed suit in the United States District Court for the Southern District of New York (SDNY) to enforce, if necessary, the arbitration award against NNPC assets residing within that jurisdiction. NNPC moved to dismiss the lawsuit. On September 4, 2019, the SDNY dismissed the Contractors' petition to recognize and enforce the Erha arbitration award. The Contractors filed a notice of appeal in the Second Circuit on October 2, 2019. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, regardless of the outcome of enforcement proceedings, the Corporation does not expect the proceedings to have a material effect upon the Corporation's operations or financial condition.

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2020	2019	2020	2019	2020	2019
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	2.80	3.50	1.60	2.30	2.80	3.50
Long-term rate of compensation increase	5.50	5.75	4.20	4.80	5.50	5.75
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	20,959	18,174	29,918	25,378	8,113	7,471
Service cost	965	757	707	551	181	139
Interest cost	708	766	657	763	277	315
Actuarial loss/(gain) *(1)*	1,287	2,562	2,344	3,703	(66)	556
Benefits paid *(2) (3)*	(1,987)	(1,300)	(1,317)	(1,196)	(510)	(517)
Foreign exchange rate changes	—	—	1,375	391	23	25
Amendments, divestments and other	(270)	—	(58)	328	117	124
Benefit obligation at December 31	21,662	20,959	33,626	29,918	8,135	8,113
Accumulated benefit obligation at December 31	17,502	16,387	30,952	27,236	—	—

(1) Actuarial loss/(gain) primarily reflects changes in discount rates, partially offset by lower long-term rates of compensation.

(2) Benefit payments for funded and unfunded plans.

(3) For 2020 and 2019, other postretirement benefits paid are net of $16 million and $20 million of Medicare subsidy receipts, respectively.

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the effective discount rate determined by use of a yield curve based on high-quality, noncallable bonds applied to the estimated cash outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using a spot yield curve of high-quality, local-currency-denominated bonds at an average maturity approximating that of the liabilities.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.5 percent in 2022 and subsequent years.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2020	2019	2020	2019	2020	2019
	(millions of dollars)					
Change in plan assets						
Fair value at January 1	13,636	11,134	22,916	19,486	425	386
Actual return on plan assets	2,269	2,521	2,795	3,210	42	54
Foreign exchange rate changes	—	—	1,011	513	—	—
Company contribution	1,004	1,022	597	602	37	41
Benefits paid *(1)*	(1,609)	(1,041)	(992)	(883)	(58)	(56)
Other	—	—	(111)	(12)	—	—
Fair value at December 31	15,300	13,636	26,216	22,916	446	425

(1) Benefit payments for funded plans.

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2020	2019	2020	2019
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(4,156)	(4,656)	(1,223)	(1,728)
Unfunded plans	(2,206)	(2,667)	(6,187)	(5,274)
Total	(6,362)	(7,323)	(7,410)	(7,002)

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2020	2019	2020	2019	2020	2019
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(6,362)	(7,323)	(7,410)	(7,002)	(7,689)	(7,688)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	—	—	1,931	1,151	—	—
Current liabilities	(377)	(242)	(273)	(267)	(327)	(351)
Postretirement benefits reserves	(5,985)	(7,081)	(9,068)	(7,886)	(7,362)	(7,337)
Total recorded	(6,362)	(7,323)	(7,410)	(7,002)	(7,689)	(7,688)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	3,102	3,971	5,904	5,662	1,164	1,339
Prior service cost	(275)	1	208	360	(274)	(315)
Total recorded in accumulated other comprehensive income	2,827	3,972	6,112	6,022	890	1,024

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

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

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2020	2019	2018	2020	2019	2018	2020	2019	2018
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					*(percent)*				
Discount rate	3.50	4.40	3.80	2.30	3.00	2.80	3.50	4.40	3.80
Long-term rate of return on funded assets	5.30	5.30	6.00	4.10	4.10	4.70	4.60	4.60	6.00
Long-term rate of compensation increase	5.75	5.75	5.75	4.80	4.30	4.30	5.75	5.75	5.75
Components of net periodic benefit cost					*(millions of dollars)*				
Service cost	965	757	819	707	551	608	181	139	152
Interest cost	708	766	721	657	763	754	277	315	301
Expected return on plan assets	(703)	(568)	(727)	(897)	(777)	(951)	(18)	(15)	(23)
Amortization of actuarial loss/(gain)	310	305	362	416	306	409	95	55	116
Amortization of prior service cost	5	5	5	68	56	46	(42)	(42)	(40)
Net pension enhancement and curtailment/ settlement cost	280	164	268	49	(98)	44	—	—	—
Net periodic benefit cost	1,565	1,429	1,448	1,000	801	910	493	452	506
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	(279)	609	479	446	1,268	(66)	(92)	517	(594)
Amortization of actuarial (loss)/gain	(590)	(469)	(630)	(442)	(208)	(453)	(95)	(55)	(116)
Prior service cost/(credit)	(271)	—	—	(82)	379	98	—	—	—
Amortization of prior service (cost)/credit	(5)	(5)	(5)	(68)	(56)	(46)	42	42	40
Foreign exchange rate changes	—	—	—	236	19	(356)	11	—	(8)
Total recorded in other comprehensive income	(1,145)	135	(156)	90	1,402	(823)	(134)	504	(678)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	420	1,564	1,292	1,090	2,203	87	359	956	(172)

Costs for defined contribution plans were $358 million, $422 million and $391 million in 2020, 2019 and 2018, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2020	2019	2018
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	1,145	(135)	156
Non-U.S. pension	(90)	(1,402)	823
Other postretirement benefits	134	(504)	678
Total (charge)/ credit to other comprehensive income, before tax	1,189	(2,041)	1,657
(Charge)/credit to income tax (see Note 4)	(153)	550	(470)
(Charge)/credit to investment in equity companies	(110)	(19)	24
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	926	(1,510)	1,211
Charge/(credit) to equity of noncontrolling interests	30	146	(114)
(Charge)/credit to other comprehensive income attributable to ExxonMobil	956	(1,364)	1,097

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

Studies are periodically conducted to establish the preferred target asset allocation percentages. The target asset allocation for the U.S. benefit plans and the major non-U.S. plans is 30 percent equity securities and 70 percent debt securities. The equity for the U.S. and certain non-U.S. plans include a small allocation to private equity partnerships that primarily focus on early-stage venture capital of 4 percent and 2 percent, respectively.

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

The 2020 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension					Non- U.S. Pension				
	Fair Value Measurement at December 31, 2020, Using:					Fair Value Measurement at December 31, 2020, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total	Level 1	Level 2	Level 3	Net Asset Value	Total
					(millions of dollars)					
Asset category:										
Equity securities										
U.S.	—	—	—	2,323	2,323	—	—	—	4,177	4,177
Non-U.S.	—	—	—	1,703	1,703	89 *(1)*	—	—	3,285	3,374
Private equity	—	—	—	548	548	—	—	—	530	530
Debt securities										
Corporate	—	5,146 *(2)*	—	1	5,147	—	138 *(2)*	—	5,212	5,350
Government	—	5,261 *(2)*	—	2	5,263	250 *(3)*	116 *(2)*	—	11,993	12,359
Asset-backed	—	—	—	1	1	—	24 *(2)*	—	239	263
Cash	—	—	—	308	308	69	21 *(4)*	—	50	140
Total at fair value	—	10,407	—	4,886	15,293	408	299	—	25,486	26,193
Insurance contracts at contract value					7					23
Total plan assets					15,300					26,216

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2020, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total
	(millions of dollars)				
Asset category:					
Equity securities					
U.S.	88 (1)	—	—	—	88
Non-U.S.	48 (1)	—	—	—	48
Debt securities					
Corporate	—	103 (2)	—	—	103
Government	—	204 (2)	—	—	204
Asset-backed	—	—	—	—	—
Cash	—	—	—	3	3
Total at fair value	136	307	—	3	446

(1) For equity securities held in separate accounts, fair value is based on observable quoted prices on active exchanges.

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

The 2019 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2019, Using:					Fair Value Measurement at December 31, 2019, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total	Level 1	Level 2	Level 3	Net Asset Value	Total
					(millions of dollars)					
Asset category:										
Equity securities										
U.S.	—	—	—	1,960	1,960	—	—	—	3,436	3,436
Non-U.S.	—	—	—	1,656	1,656	70 *(1)*	—	—	3,015	3,085
Private equity	—	—	—	499	499	—	—	—	489	489
Debt securities										
Corporate	—	4,932 *(2)*	—	1	4,933	—	129 *(2)*	—	4,486	4,615
Government	—	4,470 *(2)*	—	2	4,472	280 *(3)*	139 *(2)*	—	10,511	10,930
Asset-backed	—	—	—	1	1	—	21 *(2)*	—	212	233
Cash	—	—	—	107	107	33	12 *(4)*	—	61	106
Total at fair value	—	9,402	—	4,226	13,628	383	301	—	22,210	22,894
Insurance contracts at contract value					8					22
Total plan assets					13,636					22,916

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2019, Using:				
	Level 1	Level 2	Level 3	Net Asset Value	Total
	(millions of dollars)				
Asset category:					
Equity securities					
U.S.	—	—	—	81	81
Non-U.S.	—	—	—	49	49
Debt securities					
Corporate	—	92 (1)	—	—	92
Government	—	200 (1)	—	—	200
Asset-backed	—	—	—	—	—
Cash	—	—	—	3	3
Total at fair value	—	292	—	133	425

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

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2020	2019	2020	2019
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Accumulated benefit obligation	16,129	14,940	4,602	3,026
Fair value of plan assets	15,300	13,636	2,652	1,381
For funded pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	19,456	18,292	13,836	12,496
Fair value of plan assets	15,300	13,636	10,681	9,616
For unfunded pension plans:				
Projected benefit obligation	2,206	2,667	6,187	5,274
Accumulated benefit obligation	1,373	1,447	5,469	4,629

All other postretirement benefit plans are unfunded or underfunded.

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2021	865	395	—	—
Benefit payments expected in:				
2021	2,434	1,310	424	22
2022	1,079	1,193	426	23
2023	1,105	1,214	420	25
2024	1,124	1,240	418	26
2025	1,142	1,186	415	27
2026 - 2030	5,971	6,274	2,058	143

18. Disclosures about Segments and Related Information

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

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

Earnings after income tax include transfers at estimated market prices.

In the Corporate and financing segment, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense of $148 million in 2020, $105 million in 2019 and $84 million in 2018.

	Upstream		Downstream		Chemical		Corporate and	Corporate
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	Financing	Total
				(millions of dollars)				
As of December 31, 2020								
Earnings (Loss) after income tax	(19,385)	(645)	(852)	(225)	1,277	686	(3,296)	(22,440)
Effect of asset impairments - noncash	*(17,138)*	*(2,287)*	*(15)*	*(609)*	*(100)*	*(69)*	*(35)*	*(20,253)*
Earnings of equity companies included above	(559)	2,101	134	(190)	(21)	651	(384)	1,732
Sales and other operating revenue	5,876	8,673	48,256	92,640	8,529	14,562	38	178,574
Intersegment revenue	8,508	19,642	12,258	15,162	6,099	3,881	221	—
Depreciation and depletion expense	28,627	12,723	716	1,672	685	694	892	46,009
Interest revenue	—	—	—	—	—	—	49	49
Interest expense	52	93	1	21	—	—	991	1,158
Income tax expense (benefit)	(5,958)	742	(324)	393	440	272	(1,197)	(5,632)
Additions to property, plant and equipment	5,726	4,418	2,983	1,731	1,221	592	671	17,342
Investments in equity companies	4,792	18,135	352	879	2,543	3,514	(443)	29,772
Total assets	71,287	144,730	23,754	34,848	17,839	20,220	20,072	332,750
As of December 31, 2019								
Earnings after income tax	536	13,906	1,717	606	206	386	(3,017)	14,340
Earnings of equity companies included above	282	4,534	196	19	(4)	818	(404)	5,441
Sales and other operating revenue	9,364	13,779	70,523	134,460	9,723	17,693	41	255,583
Intersegment revenue	10,893	30,864	22,416	24,775	7,864	5,905	224	—
Depreciation and depletion expense	6,162	9,305	674	832	555	621	849	18,998
Interest revenue	—	—	—	—	—	—	84	84
Interest expense	54	34	1	9	—	1	731	830
Income tax expense (benefit)	(151)	5,509	465	361	58	305	(1,265)	5,282
Additions to property, plant and equipment	10,404	7,347	2,685	1,777	1,344	589	758	24,904
Investments in equity companies	5,313	17,736	319	1,062	1,835	3,335	(309)	29,291
Total assets	95,750	151,181	23,442	37,133	16,544	20,376	18,171	362,597
As of December 31, 2018								
Earnings after income tax	1,739	12,340	2,962	3,048	1,642	1,709	(2,600)	20,840
Earnings of equity companies included above	608	5,816	156	(6)	48	1,113	(380)	7,355
Sales and other operating revenue	10,359	15,158	74,327	147,007	12,239	20,204	38	279,332
Intersegment revenue	8,683	29,659	21,954	29,888	9,044	7,217	205	—
Depreciation and depletion expense	6,024	9,257	684	890	405	606	879	18,745
Interest revenue	—	—	—	—	—	—	64	64
Interest expense	77	31	2	12	—	1	643	766
Income tax expense (benefit)	104	8,149	946	1,008	566	245	(1,486)	9,532
Additions to property, plant and equipment	7,119	7,974	1,152	1,595	1,146	348	717	20,051
Investments in equity companies	4,566	16,337	293	1,162	870	3,431	(277)	26,382
Total assets	90,310	148,914	17,898	34,024	14,904	21,131	19,015	346,196

Geographic

Sales and other operating revenue	**2020**	**2019**	**2018**
		(millions of dollars)	
United States	62,663	89,612	96,930
Non-U.S.	115,911	165,971	182,402
Total	178,574	255,583	279,332
Significant non-U.S. revenue sources include: *(1)*			
Canada	13,093	19,735	22,672
United Kingdom	11,055	17,479	18,702
Singapore	9,442	12,128	13,689
France	8,676	12,740	13,637
Italy	7,091	10,459	13,396
Belgium	6,231	11,644	15,664
Australia	5,839	7,941	8,780

(1) Revenue is determined by primary country of operations. Excludes certain sales and other operating revenues in Non-U.S. operations where attribution to a specific country is not practicable.

	December 31,		
Long-lived assets	**2020**	**2019**	**2018**
	(millions of dollars)		
United States	94,732	114,372	108,147
Non-U.S.	132,821	138,646	138,954
Total	227,553	253,018	247,101
Significant non-U.S. long-lived assets include:			
Canada	36,232	39,130	37,433
Australia	14,792	13,933	14,548
Singapore	12,129	11,645	11,148
Kazakhstan	8,882	9,315	9,726
Papua New Guinea	7,803	8,057	8,269
Nigeria	6,345	7,640	8,421
United Arab Emirates	5,381	5,262	4,859
Russia	4,616	5,135	5,456
Angola	4,405	5,784	7,021

19. Income and Other Taxes

	2020			2019			2018		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
	(millions of dollars)								
Income tax expense (benefit)									
Federal and non-U.S.									
Current	262	2,908	3,170	(121)	6,171	6,050	459	9,001	9,460
Deferred - net	(6,045)	(2,007)	(8,052)	(255)	(420)	(675)	518	(614)	(96)
U.S. tax on non-U.S. operations	13	—	13	89	—	89	42	—	42
Total federal and non-U.S.	(5,770)	901	(4,869)	(287)	5,751	5,464	1,019	8,387	9,406
State	(763)	—	(763)	(182)	—	(182)	126	—	126
Total income tax expense (benefit)	(6,533)	901	(5,632)	(469)	5,751	5,282	1,145	8,387	9,532
All other taxes and duties									
Other taxes and duties	3,108	23,014	26,122	3,566	26,959	30,525	3,498	29,165	32,663
Included in production and manufacturing expenses	1,148	663	1,811	1,385	811	2,196	1,245	857	2,102
Included in SG&A expenses	164	328	492	160	305	465	153	312	465
Total other taxes and duties	4,420	24,005	28,425	5,111	28,075	33,186	4,896	30,334	35,230
Total	(2,113)	24,906	22,793	4,642	33,826	38,468	6,041	38,721	44,762

The above provisions for deferred income taxes include net benefits of $25 million in 2020, $740 million in 2019, and $289 million in 2018 related to changes in tax laws and rates, and a benefit of $6.3 billion in 2020 related to asset impairments.

The reconciliation between income tax expense (credit) and a theoretical U.S. tax computed by applying a rate of 21 percent for 2020, 2019 and 2018 is as follows:

	2020	2019	2018
	(millions of dollars)		
Income (Loss) before income taxes			
United States	(27,704)	(53)	5,200
Non-U.S.	(1,179)	20,109	25,753
Total	(28,883)	20,056	30,953
Theoretical tax	(6,065)	4,212	6,500
Effect of equity method of accounting	(364)	(1,143)	(1,545)
Non-U.S. taxes in excess of/(less than) theoretical U.S. tax *(1)(2)*	1,606	2,573	4,626
State taxes, net of federal tax benefit *(1)*	(603)	(144)	100
Enactment-date effects of U.S. tax reform	—	—	(291)
Other	(206)	(216)	142
Total income tax expense (credit)	(5,632)	5,282	9,532
Effective tax rate calculation			
Income tax expense (credit)	(5,632)	5,282	9,532
ExxonMobil share of equity company income taxes	861	2,490	3,142
Total income tax expense (credit)	(4,771)	7,772	12,674
Net income (loss) including noncontrolling interests	(23,251)	14,774	21,421
Total income (loss) before taxes	(28,022)	22,546	34,095
Effective income tax rate	17 %	34 %	37 %

(1) 2020 includes the impact of an increase in valuation allowance of $647 million in non-U.S. and $115 million in U.S. state jurisdictions.

(2) 2019 includes taxes less than the theoretical U.S. tax of $773 million from Norway operations and the sale of upstream assets, $657 million from a tax rate change in Alberta, Canada, and $268 million from an adjustment to a prior year tax position.

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

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

Tax effects of temporary differences for:	**2020**	**2019**
	(millions of dollars)	
Property, plant and equipment	28,778	36,029
Other liabilities	6,427	7,653
Total deferred tax liabilities	35,205	43,682
Pension and other postretirement benefits	(4,703)	(4,712)
Asset retirement obligations	(3,150)	(3,403)
Tax loss carryforwards	(8,982)	(7,404)
Other assets	(7,095)	(7,735)
Total deferred tax assets	(23,930)	(23,254)
Asset valuation allowances	2,731	1,924
Net deferred tax liabilities	14,006	22,352

In 2020, asset valuation allowances of $2,731 million increased by $807 million and included net provisions of $762 million and foreign currency effects of $41 million.

Balance sheet classification	**2020**	**2019**
	(millions of dollars)	
Other assets, including intangibles, net	(4,159)	(3,268)
Deferred income tax liabilities	18,165	25,620
Net deferred tax liabilities	14,006	22,352

The Corporation’s undistributed earnings from subsidiary companies outside the United States include amounts that have been retained to fund prior and future capital project expenditures. Deferred income taxes have not been recorded for potential future tax obligations, such as foreign withholding tax and state tax, as these undistributed earnings are expected to be indefinitely reinvested for the foreseeable future. As of December 31, 2020, it is not practicable to estimate the unrecognized deferred tax liability. However, unrecognized deferred taxes on remittance of these funds are not expected to be material.

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

Gross unrecognized tax benefits	2020	2019	2018
		(millions of dollars)	
Balance at January 1	8,844	9,174	8,783
Additions based on current year's tax positions	253	287	375
Additions for prior years' tax positions	218	120	240
Reductions for prior years' tax positions	(201)	(97)	(125)
Reductions due to lapse of the statute of limitations	(237)	(279)	(5)
Settlements with tax authorities	(113)	(538)	(68)
Foreign exchange effects/other	—	177	(26)
Balance at December 31	8,764	8,844	9,174

The gross unrecognized tax benefit balances shown above are predominantly related to tax positions that would reduce the Corporation's effective tax rate if the positions are favorably resolved. Unfavorable resolution of these tax positions generally would not increase the effective tax rate. The 2020, 2019 and 2018 changes in unrecognized tax benefits did not have a material effect on the Corporation's net income.

Resolution of these tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control of the Corporation. In the United States, the Corporation has various ongoing U.S. federal income tax positions at issue with the Internal Revenue Service (IRS) for tax years beginning in 2006. The Corporation filed a refund suit for tax years 2006-2009 in U.S. federal district court (District Court) with respect to the positions at issue for those years. These positions are reflected in the unrecognized tax benefits table above. On February 24, 2020, the Corporation received an adverse ruling on this suit. The IRS has asserted penalties associated with several of those positions. The Corporation has not recognized the penalties as an expense because the Corporation does not expect the penalties to be sustained under applicable law. On January 13, 2021, the District Court ruled that no penalties apply to the Corporation's positions in this suit. Proceedings in the District Court are continuing. Unfavorable resolution of all positions at issue with the IRS would not have a material adverse effect on the Corporation’s operations or financial condition.

It is reasonably possible that the total amount of unrecognized tax benefits could increase or decrease by 10 percent in the next 12 months.

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

Country of Operation	**Open Tax Years**		
Abu Dhabi	2018	—	2020
Angola	2018	—	2020
Australia	2010	—	2020
Belgium	2017	—	2020
Canada	2001	—	2020
Equatorial Guinea	2007	—	2020
Indonesia	2007	—	2020
Iraq	2015	—	2020
Malaysia	2011	—	2020
Nigeria	2006	—	2020
Norway	2010	—	2020
Papua New Guinea	2008	—	2020
Russia	2018	—	2020
United Kingdom	2015	—	2020
United States	2006	—	2020

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

For 2020, the Corporation's net interest expense was a credit of $6 million on income tax reserves. The Corporation incurred $0 million and $3 million in interest expense on income tax reserves in 2019 and 2018, respectively. The related interest payable balances were $61 million and $71 million at December 31, 2020, and 2019, respectively.

20. Restructuring Activities

During 2020, ExxonMobil conducted an extensive global review of staffing levels and subsequently commenced targeted workforce reductions within a number of countries to improve efficiency and reduce costs. The programs, which are expected to be substantially completed by the end of 2021, include both voluntary and involuntary employee separations and reductions in contractors.

In 2020 the Corporation recorded before-tax charges of $450 million, consisting primarily of employee separation costs, associated with announced workforce reduction programs in Europe, North America, and Australia. These costs are captured in “Selling, general and administrative expenses” on the Statement of Income and reported in the Corporate and financing segment. The Corporation estimates additional charges of up to $200 million in 2021 related to planned workforce reduction programs.

The following table summarizes the reserves and charges related to the workforce reduction programs, which are recorded in “Accounts payable and accrued liabilities.”

	2020
	(millions of dollars)
Balance at January 1	—
Additions/adjustments	450
Payments made	(47)
Balance at December 31	403

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $274 million in 2020, $3,502 million in 2019 and $1,484 million in 2018. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2020 - Revenue							
Sales to third parties	2,933	1,034	536	262	1,632	1,983	8,380
Transfers	4,943	3,938	362	4,603	5,584	509	19,939
	7,876	4,972	898	4,865	7,216	2,492	28,319
Production costs excluding taxes	3,877	3,928	786	1,911	1,471	483	12,456
Exploration expenses	51	573	33	371	112	145	1,285
Depreciation and depletion	27,489	5,118	828	2,788	2,171	733	39,127
Taxes other than income	615	106	32	390	692	152	1,987
Related income tax	(5,650)	(944)	(343)	(258)	2,130	241	(4,824)
Results of producing activities for consolidated subsidiaries	(18,506)	(3,809)	(438)	(337)	640	738	(21,712)
Equity Companies							
2020 - Revenue							
Sales to third parties	410	—	513	—	6,289	—	7,212
Transfers	308	—	12	—	60	—	380
	718	—	525	—	6,349	—	7,592
Production costs excluding taxes	545	—	674	6	421	—	1,646
Exploration expenses	—	—	2	—	—	—	2
Depreciation and depletion	560	—	224	—	543	—	1,327
Taxes other than income	34	—	22	—	2,274	—	2,330
Related income tax	—	—	(246)	(1)	1,126	—	879
Results of producing activities for equity companies	(421)	—	(151)	(5)	1,985	—	1,408
Total results of operations	(18,927)	(3,809)	(589)	(342)	2,625	738	(20,304)

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2019 - Revenue							
Sales to third parties	5,070	1,452	2,141	802	2,393	3,132	14,990
Transfers	6,544	5,979	1,345	7,892	8,706	628	31,094
	11,614	7,431	3,486	8,694	11,099	3,760	46,084
Production costs excluding taxes	4,697	4,366	1,196	2,387	1,597	637	14,880
Exploration expenses	120	498	118	234	119	180	1,269
Depreciation and depletion	5,916	1,975	601	3,019	2,264	703	14,478
Taxes other than income	998	122	113	682	1,182	250	3,347
Related income tax	(29)	(423)	(20)	1,188	4,238	599	5,553
Results of producing activities for consolidated subsidiaries	(88)	893	1,478	1,184	1,699	1,391	6,557
Equity Companies							
2019 - Revenue							
Sales to third parties	664	—	1,248	—	10,536	—	12,448
Transfers	530	—	6	—	464	—	1,000
	1,194	—	1,254	—	11,000	—	13,448
Production costs excluding taxes	595	—	570	6	555	—	1,726
Exploration expenses	1	—	4	—	—	—	5
Depreciation and depletion	379	—	231	—	528	—	1,138
Taxes other than income	33	—	75	—	3,634	—	3,742
Related income tax	—	—	180	(1)	2,275	—	2,454
Results of producing activities for equity companies	186	—	194	(5)	4,008	—	4,383
Total results of operations	98	893	1,672	1,179	5,707	1,391	10,940
Consolidated Subsidiaries							
2018 - Revenue							
Sales to third parties	5,914	1,491	3,680	1,136	2,431	3,256	17,908
Transfers	5,822	4,633	1,573	8,844	8,461	873	30,206
	11,736	6,124	5,253	9,980	10,892	4,129	48,114
Production costs excluding taxes	3,915	4,211	1,348	2,454	1,501	680	14,109
Exploration expenses	237	434	140	318	209	128	1,466
Depreciation and depletion	5,775	1,803	665	2,788	2,088	809	13,928
Taxes other than income	953	133	128	799	1,155	335	3,503
Related income tax	250	(121)	1,934	1,766	4,008	622	8,459
Results of producing activities for consolidated subsidiaries	606	(336)	1,038	1,855	1,931	1,555	6,649
Equity Companies							
2018 - Revenue							
Sales to third parties	747	—	1,420	—	12,028	—	14,195

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $13,206 million less at year-end 2020 and $13,082 million less at year-end 2019 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
Consolidated Subsidiaries								
As of December 31, 2020								
Property (acreage) costs	– Proved	18,059	2,151	51	1,332	2,979	771	25,343
	– Unproved	23,255	7,352	37	213	181	2,642	33,680
Total property costs		41,314	9,503	88	1,545	3,160	3,413	59,023
Producing assets		104,650	52,552	20,286	55,556	43,394	15,348	291,786
Incomplete construction		5,549	4,590	1,446	1,975	3,050	1,972	18,582
Total capitalized costs		151,513	66,645	21,820	59,076	49,604	20,733	369,391
Accumulated depreciation and depletion		89,401	26,635	19,193	46,567	24,701	8,628	215,125
Net capitalized costs for consolidated subsidiaries		62,112	40,010	2,627	12,509	24,903	12,105	154,266
Equity Companies								
As of December 31, 2020								
Property (acreage) costs	– Proved	98	—	4	286	—	—	388
	– Unproved	4	—	—	3,134	—	—	3,138
Total property costs		102	—	4	3,420	—	—	3,526
Producing assets		6,975	—	5,932	—	8,547	—	21,454
Incomplete construction		138	—	34	721	10,527	—	11,420
Total capitalized costs		7,215	—	5,970	4,141	19,074	—	36,400
Accumulated depreciation and depletion		3,854	—	5,462	—	5,911	—	15,227
Net capitalized costs for equity companies		3,361	—	508	4,141	13,163	—	21,173
Consolidated Subsidiaries								
As of December 31, 2019								
Property (acreage) costs	– Proved	19,046	2,579	49	988	2,971	719	26,352
	– Unproved	23,725	7,113	37	166	181	2,638	33,860
Total property costs		42,771	9,692	86	1,154	3,152	3,357	60,212
Producing assets		99,405	49,942	18,982	55,436	41,181	13,670	278,616
Incomplete construction		6,086	4,315	1,514	2,717	4,299	1,811	20,742
Total capitalized costs		148,262	63,949	20,582	59,307	48,632	18,838	359,570
Accumulated depreciation and depletion		63,333	21,533	17,544	43,743	22,497	7,235	175,885
Net capitalized costs for consolidated								

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2020 were $11,254 million, down $7,986 million from 2019, due primarily to lower development costs including lower asset retirement obligation cost estimates mainly in Angola. In 2019, costs were $19,240 million, up $2,912 million from 2018, due primarily to higher development costs, partially offset by lower acquisition costs of unproved properties. Total equity company costs incurred in 2020 were $2,012 million, down $904 million from 2019, due primarily to lower development costs.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
During 2020								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	1	30	—	344	7	—	382
	– Unproved	80	3	—	47	—	—	130
Exploration costs		60	702	40	232	110	83	1,227
Development costs		5,675	2,059	316	(239)	974	730	9,515
Total costs incurred for consolidated subsidiaries		5,816	2,794	356	384	1,091	813	11,254
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		—	—	2	—	—	—	2
Development costs		135	—	20	71	1,784	—	2,010
Total costs incurred for equity companies		135	—	22	71	1,784	—	2,012
During 2019								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	12	—	—	—	26	—	38
	– Unproved	226	105	1	20	—	—	352
Exploration costs		134	1,107	155	252	111	194	1,953
Development costs		10,275	2,946	809	1,066	1,317	484	16,897
Total costs incurred for consolidated subsidiaries		10,647	4,158	965	1,338	1,454	678	19,240
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		1	—	5	—	—	—	6
Development costs		241	—	15	69	2,585	—	2,910
Total costs incurred for equity companies		242	—	20	69	2,585	—	2,916
During 2018								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	7	3	—	—	321	—	331
	– Unproved	238	2,109	—	1	—	—	2,348
Exploration costs		235	1,113	147	342	217	174	2,228
Development costs		7,440	1,734	96	791	1,104	256	11,421
Total costs incurred for consolidated subsidiaries		7,920	4,959	243	1,134	1,642	430	16,328
Equity Companies								
Property acquisition		21						21

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2018, 2019 and 2020.

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

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

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

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

During the first and second quarters of 2020, the balance of supply and demand for petroleum and petrochemical products experienced two significant disruptive effects. On the demand side, the COVID-19 pandemic spread rapidly through most areas of the world resulting in substantial reductions in consumer and business activity and significantly reduced demand for crude oil, natural gas, and petroleum products. This reduction in demand coincided with announcements of increased production in certain key oil-producing countries which led to increases in inventory levels and sharp declines in prices for crude oil, natural gas, and petroleum products. Market conditions continued to reflect considerable uncertainty throughout 2020.

Primarily as a result of very low prices during 2020 and the effects of reductions in capital expenditures, under the SEC definition of proved reserves, certain quantities of crude oil, bitumen, and natural gas that qualified as proved reserves in prior years did not qualify as proved reserves at year-end 2020. Amounts no longer qualifying as proved reserves include 3.1 billion barrels of bitumen at Kearl, 0.6 billion barrels of bitumen at Cold Lake, and 0.5 billion oil-equivalent barrels in the United States. The Corporation's near-term reduction in capital expenditures resulted in a net reduction to estimates of proved reserves of approximately 1.5 billion oil-equivalent barrels, mainly related to unconventional drilling in the United States. Among the factors that could result in portions of these amounts being recognized again as proved reserves at some point in the future are a recovery in the SEC price basis, cost reductions, operating efficiencies, and increases in planned capital spending.

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

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

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The production and reserves reported for these types of arrangements typically vary inversely with oil and natural gas price changes. As oil and natural gas prices increase, the cash flow and value received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2020 that were associated with production sharing contract arrangements was 15 percent of liquids, 14 percent of natural gas and 15 percent on an oil-equivalent basis (natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels).

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

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

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

	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
					(millions of barrels)						
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2018	2,695	410	119	729	3,496	110	7,559	1,258	1,012	473	10,302
Revisions	61	28	63	(9)	4	6	153	(16)	3,286	15	3,438
Improved recovery	—	—	23	13	—	—	36	—	—	—	36
Purchases	8	—	—	—	—	—	8	2	—	—	10
Sales	(11)	—	(2)	—	—	—	(13)	(13)	—	—	(26)
Extensions/discoveries	595	113	—	9	3	—	720	238	—	—	958
Production	(144)	(22)	(37)	(138)	(146)	(11)	(498)	(65)	(113)	(22)	(698)
December 31, 2018	3,204	529	166	604	3,357	105	7,965	1,404	4,185	466	14,020
Attributable to noncontrolling interests		*44*						*4*	*962*	*142*	
Proportional interest in proved reserves of equity companies											
January 1, 2018	245	—	15	6	1,097	—	1,363	364	—	—	1,727
Revisions	28	—	1	—	6	—	35	1	—	—	36
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	1	—	—	—	—	—	1	—	—	—	1
Production	(20)	—	(1)	—	(83)	—	(104)	(23)	—	—	(127)
December 31, 2018	254	—	15	6	1,020	—	1,295	342	—	—	1,637
Total liquids proved reserves at December 31, 2018	3,458	529	181	610	4,377	105	9,260	1,746	4,185	466	15,657
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2019	3,204	529	166	604	3,357	105	7,965	1,404	4,185	466	14,020
Revisions	(677)	(66)	20	(25)	136	—	(612)	(305)	(213)	(27)	(1,157)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	20	—	—	—	—	—	20	12	—	—	32
Sales	(1)	—	(117)	—	—	—	(118)	(27)	—	—	(145)
Extensions/discoveries	710	125	—	—	—	—	835	263	—	—	1,098
Production	(168)	(31)	(30)	(132)	(158)	(11)	(530)	(72)	(114)	(24)	(740)
December 31, 2019	3,088	557	39	447	3,335	94	7,560	1,275	3,858	415	13,108
Attributable to noncontrolling interests		*21*						*3*	*894*	*126*	
Proportional interest in											

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

	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2020	3,088	557	39	447	3,335	94	7,560	1,275	3,858	415	13,108
Revisions	(1,139)	(14)	(9)	19	(20)	(10)	(1,173)	(209)	(3,653)	(79)	(5,114)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	(1)	(2)	—	—	—	—	(3)	(3)	—	—	(6)
Extensions/discoveries	187	1	—	—	—	—	188	65	1	133	387
Production	(176)	(45)	(8)	(110)	(165)	(10)	(514)	(74)	(125)	(25)	(738)
December 31, 2020	1,959	497	22	356	3,150	74	6,058	1,054	81	444	7,637
Attributable to noncontrolling interests		*7*						*1*	*25*	*135*	
Proportional interest in proved reserves of equity companies											
January 1, 2020	251	—	14	6	897	—	1,168	322	—	—	1,490
Revisions	(102)	—	(4)	—	4	—	(102)	(22)	—	—	(124)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	—	—	—	—	—	—	—	—	—
Production	(18)	—	(1)	—	(76)	—	(95)	(23)	—	—	(118)
December 31, 2020	131	—	9	6	825	—	971	277	—	—	1,248
Total liquids proved reserves at December 31, 2020	2,090	497	31	362	3,975	74	7,029	1,331	81	444	8,885

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ Other Americas	Canada/ Other Americas	Total
	(millions of barrels)									
Proved developed reserves, as of December 31, 2018										
Consolidated subsidiaries	1,696	153	123	578	2,285	118	4,953	3,880	466	9,299
Equity companies	208	—	15	—	919	—	1,142	—	—	1,142
Proved undeveloped reserves, as of December 31, 2018										
Consolidated subsidiaries	2,616	403	78	111	1,173	35	4,416	305	—	4,721
Equity companies	56	—	—	6	433	—	495	—	—	495
Total liquids proved reserves at December 31, 2018	4,576	556	216	695	4,810	153	11,006	4,185	466	15,657
Proved developed reserves, as of December 31, 2019										
Consolidated subsidiaries	1,655	195	23	419	2,309	90	4,691	3,528	415	8,634
Equity companies	200	—	13	—	727	—	940	—	—	940
Proved undeveloped reserves, as of December 31, 2019										
Consolidated subsidiaries	2,474	381	29	68	1,157	35	4,144	330	—	4,474
Equity companies	60	—	1	6	483	—	550	—	—	550
Total liquids proved reserves at December 31, 2019	4,389	576	66	493	4,676	125	10,325	3,858	415	14,598
Proved developed reserves, as of December 31, 2020										
Consolidated subsidiaries	1,473	293	13	345	2,299	67	4,490	76	311	4,877
Equity companies	111	—	8	—	646	—	765	—	—	765
Proved undeveloped reserves, as of December 31, 2020										
Consolidated subsidiaries	1,342	209	16	42	975	38	2,622	5	133	2,760
Equity companies	24	—	1	6	452	—	483	—	—	483

(1) See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional information on natural gas liquids proved reserves see Item 2. Properties in ExxonMobil's 2020 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	**Total All Products *(1)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2018	19,033	1,372	1,368	595	4,340	6,894	33,602	15,903
Revisions	(98)	(29)	306	38	(147)	1,065	1,135	3,626
Improved recovery	—	—	—	—	—	—	—	36
Purchases	104	—	—	—	—	—	104	27
Sales	(264)	(3)	(4)	—	—	—	(271)	(71)
Extensions/discoveries	3,658	506	3	—	1	7	4,175	1,654
Production	(1,030)	(102)	(361)	(45)	(353)	(504)	(2,395)	(1,097)
December 31, 2018	21,403	1,744	1,312	588	3,841	7,462	36,350	20,078
Attributable to noncontrolling interests		*334*						
Proportional interest in proved reserves of equity companies								
January 1, 2018	223	—	6,164	914	14,248	—	21,549	5,318
Revisions	12	—	(4,801)	(51)	102	—	(4,738)	(753)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	(38)	—	—	—	(38)	(6)
Extensions/discoveries	2	—	—	—	—	—	2	1
Production	(12)	—	(268)	—	(1,029)	—	(1,309)	(345)
December 31, 2018	225	—	1,057	863	13,321	—	15,466	4,215
Total proved reserves at December 31, 2018	21,628	1,744	2,369	1,451	17,162	7,462	51,816	24,293
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2019	21,403	1,744	1,312	588	3,841	7,462	36,350	20,078
Revisions	(3,213)	(301)	41	(171)	953	39	(2,652)	(1,599)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	85	—	—	—	—	—	85	47
Sales	(297)	(29)	(416)	—	—	—	(742)	(269)
Extensions/discoveries	2,151	166	—	—	—	—	2,317	1,484
Production	(1,103)	(114)	(316)	(40)	(361)	(500)	(2,434)	(1,145)
December 31, 2019	19,026	1,466	621	377	4,433	7,001	32,924	18,596
Attributable to noncontrolling interests		*256*						
Proportional interest in proved reserves of equity companies								
January 1, 2019	225	—	1,057	863	13,321	—	15,466	4,215
Revisions	(1)	—	(238)	45	142	—	(52)	(29)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent Total All Products (1)
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2020	19,026	1,466	621	377	4,433	7,001	32,924	18,596
Revisions	(4,904)	(753)	(4)	(23)	245	(405)	(5,844)	(6,088)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	(35)	(30)	—	—	—	—	(65)	(17)
Extensions/discoveries	433	1	1	—	—	—	435	459
Production	(1,081)	(123)	(177)	(34)	(369)	(462)	(2,246)	(1,113)
December 31, 2020	13,439	561	441	320	4,309	6,134	25,204	11,837
Attributable to noncontrolling interests		*84*						
Proportional interest in proved reserves of equity companies								
January 1, 2020	213	—	581	908	12,454	—	14,156	3,849
Revisions	(99)	—	(95)	9	(106)	—	(291)	(172)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	—	—	—	—	—	—
Production	(12)	—	(126)	—	(971)	—	(1,109)	(303)
December 31, 2020	102	—	360	917	11,377	—	12,756	3,374
Total proved reserves at December 31, 2020	13,541	561	801	1,237	15,686	6,134	37,960	15,211

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent Total All Products (1)
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Proved developed reserves, as of December 31, 2018								
Consolidated subsidiaries	12,538	605	1,116	581	3,618	4,336	22,794	13,098
Equity companies	152	—	988	—	11,951	—	13,091	3,324
Proved undeveloped reserves, as of December 31, 2018								
Consolidated subsidiaries	8,865	1,139	196	7	223	3,126	13,556	6,980
Equity companies	73	—	69	863	1,370	—	2,375	891
Total proved reserves at December 31, 2018	21,628	1,744	2,369	1,451	17,162	7,462	51,816	24,293
Proved developed reserves, as of December 31, 2019								
Consolidated subsidiaries	11,882	613	502	377	3,508	3,765	20,647	12,075
Equity companies	143	—	505	—	9,859	—	10,507	2,691
Proved undeveloped reserves, as of December 31, 2019								
Consolidated subsidiaries	7,144	853	119	—	925	3,236	12,277	6,521
Equity companies	70	—	76	908	2,595	—	3,649	1,158
Total proved reserves at December 31, 2019	19,239	1,466	1,202	1,285	16,887	7,001	47,080	22,445
Proved developed reserves, as of December 31, 2020								
Consolidated subsidiaries	10,375	472	399	318	3,323	3,344	18,231	7,915
Equity companies	83	—	293	—	8,992	—	9,368	2,326
Proved undeveloped reserves, as of December 31, 2020								
Consolidated subsidiaries	3,064	89	42	2	986	2,790	6,973	3,922
Equity companies	19	—	67	917	2,385	—	3,388	1,048
Total proved reserves at December 31, 2020	13,541	561	801	1,237	15,686	6,134	37,960	15,211

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

Standardized Measure of Discounted Future Cash Flows

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

Standardized Measure of Discounted Future Cash Flows	**United States**	**Canada/ Other Americas** *(1)*	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2018							
Future cash inflows from sales of oil and gas	265,527	204,596	23,263	47,557	241,410	67,041	849,394
Future production costs	96,489	125,469	5,023	16,019	61,674	18,081	322,755
Future development costs	54,457	29,759	7,351	8,356	13,907	8,047	121,877
Future income tax expenses	25,365	9,024	8,255	10,491	124,043	10,499	187,677
Future net cash flows	89,216	40,344	2,634	12,691	41,786	30,414	217,085
Effect of discounting net cash flows at 10%	49,176	22,315	(6)	2,957	21,509	15,030	110,981
Discounted future net cash flows	40,040	18,029	2,640	9,734	20,277	15,384	106,104
Equity Companies							
As of December 31, 2018							
Future cash inflows from sales of oil and gas	17,730	—	7,264	3,777	165,471	—	194,242
Future production costs	6,474	—	2,157	249	61,331	—	70,211
Future development costs	3,359	—	1,165	370	10,295	—	15,189
Future income tax expenses	—	—	1,612	964	30,662	—	33,238
Future net cash flows	7,897	—	2,330	2,194	63,183	—	75,604
Effect of discounting net cash flows at 10%	4,104	—	713	1,712	31,503	—	38,032
Discounted future net cash flows	3,793	—	1,617	482	31,680	—	37,572
Total consolidated and equity interests in standardized measure of discounted future net cash flows	43,833	18,029	4,257	10,216	51,957	15,384	143,676

(1) Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $2,823 million in 2018.

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ Other Americas *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
			(millions of dollars)				
Consolidated Subsidiaries							
As of December 31, 2019							
Future cash inflows from sales of oil and gas	208,981	190,604	5,789	30,194	215,837	43,599	695,004
Future production costs	90,448	133,606	3,209	10,177	58,255	12,980	308,675
Future development costs	53,641	31,158	4,397	6,756	14,113	8,109	118,174
Future income tax expenses	12,530	5,888	(594)	5,374	108,316	5,158	136,672
Future net cash flows	52,362	19,952	(1,223)	7,887	35,153	17,352	131,483
Effect of discounting net cash flows at 10%	30,499	7,728	(1,265)	872	18,658	7,491	63,983
Discounted future net cash flows	21,863	12,224	42	7,015	16,495	9,861	67,500
Equity Companies							
As of December 31, 2019							
Future cash inflows from sales of oil and gas	15,729	—	3,194	2,509	115,451	—	136,883
Future production costs	6,848	—	1,302	246	48,259	—	56,655
Future development costs	3,681	—	1,182	247	11,463	—	16,573
Future income tax expenses	—	—	346	555	17,891	—	18,792
Future net cash flows	5,200	—	364	1,461	37,838	—	44,863
Effect of discounting net cash flows at 10%	2,721	—	41	1,112	18,573	—	22,447
Discounted future net cash flows	2,479	—	323	349	19,265	—	22,416
Total consolidated and equity interests in standardized measure of discounted future net cash flows	24,342	12,224	365	7,364	35,760	9,861	89,916
Consolidated Subsidiaries							
As of December 31, 2020							
Future cash inflows from sales of oil and gas	93,520	38,193	2,734	15,411	138,080	19,794	307,732
Future production costs	53,635	19,971	1,815	6,527	42,378	3,188	127,514
Future development costs	27,668	10,991	4,244	6,223	13,432	7,580	70,138
Future income tax expenses	(2,509)	851	(1,121)	916	62,223	1,381	61,741
Future net cash flows	14,726	6,380	(2,204)	1,745	20,047	7,645	48,339
Effect of discounting net cash flows at 10%	8,564	1,116	(1,565)	(511)	10,557	3,624	21,785
Discounted future net cash flows	6,162	5,264	(639)	2,256	9,490	4,021	26,554
Equity Companies							
As of December 31, 2020							
Future cash inflows from sales of oil and gas	5,304	—	1,511	740	63,105	—	70,660
Future production costs	3,467	—	694	247	29,170	—	33,578
Future development costs	2,243	—	1,054	163	9,929	—	13,389

(1) Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $1,064 million in 2019 and $(150) million in 2020.

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

Consolidated and Equity Interests	2018		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2017	65,201	25,003	90,204
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/sales less related costs	9,472	(134)	9,338
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(31,706)	(9,956)	(41,662)
Development costs incurred during the year	11,500	2,762	14,262
Net change in prices, lifting and development costs	56,798	23,582	80,380
Revisions of previous reserves estimates	14,515	(2,091)	12,424
Accretion of discount	8,793	3,043	11,836
Net change in income taxes	(28,469)	(4,637)	(33,106)
Total change in the standardized measure during the year	40,903	12,569	53,472
Discounted future net cash flows as			

Consolidated and Equity Interests	2019		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2018	106,104	37,572	143,676
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/ sales less related costs	(1,252)	4	(1,248)
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(29,159)	(8,202)	(37,361)
Development costs incurred during the year	16,544	2,927	19,471
Net change in prices, lifting and development costs	(66,455)	(21,046)	(87,501)
Revisions of previous reserves estimates	4,906	657	5,563
Accretion of discount	11,433	3,956	15,389
Net change in income taxes	25,379	6,548	31,927
Total change in the standardized measure during the year	(38,604)	(15,156)	(53,760)
Discounted future net cash flows as of December 31,	67,500	22,416	89,916

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

Consolidated and Equity Interests (continued)	**2020**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2019	67,500	22,416	89,916
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/sales less related costs	169	—	169
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(15,048)	(3,818)	(18,866)
Development costs incurred during the year	9,969	1,760	11,729
Net change in prices, lifting and development costs	(80,444)	(21,739)	(102,183)
Revisions of previous reserves estimates	2,614	680	3,294
Accretion of discount	10,786	3,011	13,797
Net change in income taxes	31,008	6,131	37,139
Total change in the standardized measure during the year	(40,946)	(13,975)	(54,921)
Discounted future net cash flows as of December 31, 2020	26,554	8,441	34,995

OPERATING INFORMATION (unaudited)

	2020	2019	2018
Production of crude oil, natural gas liquids, bitumen and synthetic oil			
Net production	*(thousands of barrels daily)*		
United States	685	646	551
Canada/Other Americas	536	467	438
Europe	30	108	132
Africa	312	372	387
Asia	742	748	711
Australia/Oceania	44	45	47
Worldwide	2,349	2,386	2,266
Natural gas production available for sale			
Net production	*(millions of cubic feet daily)*		
United States	2,691	2,778	2,574
Canada/Other Americas	277	258	227
Europe	789	1,457	1,653
Africa	9	7	13
Asia	3,486	3,575	3,613
Australia/Oceania	1,219	1,319	1,325
Worldwide	8,471	9,394	9,405
	(thousands of oil-equivalent barrels daily)		
Oil-equivalent production *(1)*	3,761	3,952	3,833
Refinery throughput	*(thousands of barrels daily)*		
United States	1,549	1,532	1,588
Canada	340	353	392
Europe	1,173	1,317	1,422
Asia Pacific	553	598	706
Other Non-U.S.	158	181	164
Worldwide	3,773	3,981	4,272
Petroleum product sales *(2)*			
United States	2,154	2,292	2,210
Canada	418	476	510
Europe	1,253	1,479	1,556
Asia Pacific and other Eastern Hemisphere	1,014	1,156	1,200
Latin America	56	49	36
Worldwide	4,895	5,452	5,512
Gasoline, naphthas	1,994	2,220	2,217
Heating oils, kerosene, diesel oils	1,751	1,867	1,840
Aviation fuels	213	406	402
Heavy fuels	249	270	395
Specialty petroleum products	688	689	658
Worldwide	4,895	5,452	5,512
Chemical prime product sales *(2)*	*(thousands of metric tons)*		
United States	9,010	9,127	9,824

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

(1) 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.

INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the Registrant's Annual Report on Form 10-K for 2015).
3(ii)	By-Laws, as revised effective March 1, 2020 (incorporated by reference to Exhibit 3(ii) to the Registrant's Report on Form 8-K of March 3, 2020).
4(vi)	Description of ExxonMobil Capital Stock (incorporated by reference to Exhibit 4(vi) to the Registrant's Annual Report on Form 10-K for 2019).
10(iii)(a.1)	2003 Incentive Program, as approved by shareholders May 28, 2003 (incorporated by reference to Exhibit 10(iii)(a.1) to the Registrant's Annual Report on Form 10-K for 2017).*
10(iii)(a.2)	Extended Provisions for Restricted Stock Agreements (incorporated by reference to Exhibit 10(iii)(a.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements – Settlement in Shares (incorporated by reference to Exhibit 99.1 to the Registrant's report on Form 8-K of December 1, 2020).*
10(iii)(b.1)	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 10(iii)(b.1) to the Registrant's Annual Report on Form 10-K for 2018).*
10(iii)(b.2)	Earnings Bonus Unit instrument (incorporated by reference to Exhibit 10(iii)(b.2) to the Registrant's Annual Report on Form 10-K for 2019).*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant's Annual Report on Form 10-K for 2014).*
10(iii)(c.3)	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant's Annual Report on Form 10-K for 2018).*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f.1) to the Registrant's Annual Report on Form 10-K for 2018).*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by reference to Exhibit 10(iii)(f.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors.*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated March 1, 2020 (incorporated by reference to Exhibit 10(iii)(f.4) to the Registrant's Report on Form 10-Q for the quarter ended March 31, 2020).*
14	Code of Ethics and Business Conduct (incorporated by reference to Exhibit 14 to the Registrant's

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

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

SIGNATURES

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

EXXON MOBIL CORPORATION

By: /s/ DARREN W. WOODS

(Darren W. Woods,
Chairman of the Board)

Dated February 24, 2021

POWER OF ATTORNEY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated and on February 24, 2021.

/s/ DARREN W. WOODS	Chairman of the Board
(Darren W. Woods)	(Principal Executive Officer)
/s/ SUSAN K. AVERY	Director
(Susan K. Avery)	
/s/ ANGELA F. BRALY	Director
(Angela F. Braly)	
/s/ URSULA M. BURNS	Director
(Ursula M. Burns)	

/s/ KENNETH C. FRAZIER (Kenneth C. Frazier)	Director
/s/ JOSEPH L. HOOLEY (Joseph L. Hooley)	Director
/s/ STEVEN A. KANDARIAN (Steven A. Kandarian)	Director
/s/ DOUGLAS R. OBERHELMAN (Douglas R. Oberhelman)	Director
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director
/s/ WILLIAM C. WELDON (William C. Weldon)	Director
/s/ WAN ZULKIFLEE (Wan Zulkiflee)	Director
/s/ ANDREW P. SWIGER (Andrew P. Swiger)	Senior Vice President (Principal Financial Officer)
/s/ DAVID S. ROSENTHAL (David S. Rosenthal)	Vice President and Controller (Principal Accounting Officer)

2019

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, 2019

or

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

For the transition period from _______ to _______

Commission File Number 1-2256

Exxon Mobil Corporation

(Exact name of registrant as specified in its charter)

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

5959 Las Colinas Boulevard, Irving, Texas 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 940-6000

(Registrant's telephone number, including area code)

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

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, without par value	**XOM**	**New York Stock Exchange**

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 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 28, 2019, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $76.63 on the New York Stock Exchange composite tape, was in excess of $324 billion.

Class	Outstanding as of January 31, 2020
Common stock, without par value	**4,232,190,744**

Documents Incorporated by Reference: Proxy Statement for the 2020 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2019

TABLE OF CONTENTS

PART I

PART II

PART I

ITEM 1. BUSINESS

Exxon Mobil Corporation was incorporated in the State of New Jersey in 1882. Divisions and affiliated companies of ExxonMobil operate or market products in the United States and most other countries of the world. Their principal business 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 over 13 thousand active patents worldwide at the end of 2019. For technology licensed to third parties, revenues totaled approximately $79 million in 2019. 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 74.9 thousand, 71.0 thousand, and 69.6 thousand at years ended 2019, 2018, and 2017, 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 2019 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $5.2 billion, of which $4.0 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $5.9 billion in 2020 and 2021. Capital expenditures are expected to account for approximately 35 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. 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, Code of Ethics and Business Conduct, and additional policies as well as the charters of the audit, compensation, nominating, and other 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, trade tariffs, security or public health concerns, 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 that alter fuel choices, such as technological advances in energy storage that make wind and solar more competitive for power generation; changes in consumer preferences for our products, including consumer demand for alternative fueled or electric transportation; 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 use of 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; by government enforcement proceedings alleging non-compliance with applicable laws or regulations; or by state and local government actors as well as private plaintiffs acting in parallel that attempt to use the legal system to promote public policy agendas, gain political notoriety, or obtain monetary awards from the Company.

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.

Alternative energy. Many governments are providing tax advantages and other subsidies to support transitioning to 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 launching an innovative relationship with the U.S. Department of Energy's National Laboratory network to bring low-emission energy breakthroughs to commercial scale. 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 and strategies to divest assets. We may not be able to divest assets at a price or on the timeline we contemplate in our strategies. Additionally, we may retain certain liabilities following a divestment and could be held liable for past use or for different liabilities than anticipated.

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, including successfully applying advances in the ability to process very large amounts of data to our businesses.

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 and as partners with other private firms. 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, change in consumer views concerning our products, 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, obtain financing, 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 2019

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, 2019, that would cause a significant change in the estimated proved reserves as of that date.

						Oil-Equivalent
	Crude	Natural Gas		Synthetic	Natural	Total
	Oil	Liquids	Bitumen	Oil	Gas	All Products
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million bbls)*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,226	429	-	-	11,882	3,635
Canada/Other Americas *(1)*	185	10	3,528	415	613	4,240
Europe	20	3	-	-	502	107
Africa	384	35	-	-	377	482
Asia	2,217	92	-	-	3,508	2,894
Australia/Oceania	63	27	-	-	3,765	717
Total Consolidated	4,095	596	3,528	415	20,647	12,075
Equity Companies						
United States	195	5	-	-	143	224
Europe	13	-	-	-	505	97
Africa	-	-	-	-	-	-
Asia	499	228	-	-	9,859	2,370

Total Equity Company	707	233	-	-	10,507	2,691
Total Developed	4,802	829	3,528	415	31,154	14,766
Undeveloped						
Consolidated Subsidiaries						
United States	1,862	612	-	-	7,144	3,665
Canada/Other Americas *(1)*	372	9	330	-	853	853
Europe	19	10	-	-	119	49
Africa	63	5	-	-	-	68
Asia	1,118	39	-	-	925	1,311
Australia/Oceania	31	4	-	-	3,236	575
Total Consolidated	3,465	679	330	-	12,277	6,521
Equity Companies						
United States	56	4	-	-	70	71
Europe	1	-	-	-	76	14
Africa	6	-	-	-	908	157
Asia	398	85	-	-	2,595	916
Total Equity Company	461	89	-	-	3,649	1,158
Total Undeveloped	3,926	768	330	-	15,926	7,679
Total Proved Reserves	8,728	1,597	3,858	415	47,080	22,445

(1) Other Americas includes proved developed reserves of 18 million barrels of crude oil and 75 billion cubic feet of natural gas, as well as proved undeveloped reserves of 280 million barrels of crude oil and 292 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 2019

Additions to ExxonMobil's proved reserves in 2019 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 and Resources 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 and Resources group has more than 30 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 15 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 degrees in either Engineering or Geology.

The Global Reserves and Resources 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, commercial and market assessments, analysis of well and field performance, and long-standing approval guidelines. 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 geoscience and engineering professionals within the operating organization. In addition, changes to reserves estimates that exceed certain thresholds require further review and approval by the appropriate level of management within the operating organization before the changes may be made in the central database. Endorsement by the Global Reserves and Resources 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 2019, approximately 7.7 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 34 percent of the 22.4 GOEB reported in proved reserves. This compares to the 7.9 GOEB of proved undeveloped reserves reported at the end of 2018. During the year, ExxonMobil conducted development activities that resulted in the transfer of approximately 0.9 GOEB from proved undeveloped to proved developed reserves by year end. The largest transfers were related to development activities in the United States, the United Arab Emirates, and Kazakhstan. During 2019, extensions and discoveries, primarily in the United States and Guyana, resulted in an addition of 1.5 GOEB of proved undeveloped reserves, along with an increase of 0.6 GOEB due to revisions primarily in Asia. Also, the Corporation reclassified approximately 1.4 GOEB of proved undeveloped reserves which no longer met the SEC definition of proved reserves, primarily in the United States, which was offset by the extensions in the United States referenced above.

Overall, investments of $18.3 billion were made by the Corporation during 2019 to progress the development of reported proved undeveloped reserves, including $17.7 billion for oil and gas producing activities, along with additional investments for other non-oil and gas producing activities such as the construction of support infrastructure and other related facilities. These investments represented 78 percent of the $23.5 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 Tengizchevroil joint venture development that 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.

	2019		2018		2017	
	(thousands of barrels daily)					
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries						
United States	461	131	395	101	361	96
Canada/Other Americas *(1)*	87	4	62	6	44	6
Europe	84	21	101	27	147	31
Africa	360	12	377	10	412	11
Asia	432	22	398	25	373	26
Australia/Oceania	30	15	31	16	35	19
Total Consolidated Subsidiaries	1,454	205	1,364	185	1,372	189
Equity Companies						
United States	52	2	54	1	55	2
Europe	3	-	4	-	4	-
Asia	232	62	226	62	235	64
Total Equity Companies	287	64	284	63	294	66
Total crude oil and natural gas liquids production	1,741	269	1,648	248	1,666	255
Bitumen production						
Consolidated Subsidiaries						
Canada/Other Americas	311		310		305	
Synthetic oil production						

Consolidated Subsidiaries			
Canada/Other Americas	65	60	57
Total liquids production	2,386	2,266	2,283

	(millions of cubic feet daily)		
Natural gas production available for sale			
Consolidated Subsidiaries			
United States	2,756	2,550	2,910
Canada/Other Americas *(1)*	258	227	218
Europe	808	925	1,046
Africa	7	13	5
Asia	851	838	906
Australia/Oceania	1,319	1,325	1,310
Total Consolidated Subsidiaries	5,999	5,878	6,395
Equity Companies			
United States	22	24	26
Europe	649	728	902
Asia	2,724	2,775	2,888
Total Equity Companies	3,395	3,527	3,816
Total natural gas production available for sale	9,394	9,405	10,211

	(thousands of oil-equivalent barrels daily)		
Oil-equivalent production	3,952	3,833	3,985

(1) Other Americas includes crude oil production for 2019 and 2018 of two thousand barrels daily and natural gas production available for sale for 2019, 2018 and 2017 of 36 million, 28 million, and 24 million cubic feet daily, respectively.

B. Production Prices and Production Costs

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

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2019				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	54.41	59.39	63.59	65.64	64.14	61.08	61.04
NGL, per barrel	18.94	16.59	30.56	41.41	24.64	30.55	22.85
Natural gas, per thousand cubic feet	1.54	1.44	4.50	1.49	2.07	6.26	3.05
Bitumen, per barrel	-	36.25	-	-	-	-	36.25
Synthetic oil, per barrel	-	56.18	-	-	-	-	56.18
Average production costs, per oil-equivalent barrel - total	12.25	23.41	13.69	17.51	7.34	6.60	13.43
Average production costs, per barrel - bitumen	-	24.18	-	-	-	-	24.18
Average production costs, per barrel - synthetic oil	-	40.38	-	-	-	-	40.38
Equity Companies							
Average production prices							
Crude oil, per barrel	60.95	-	58.72	-	58.74	-	59.15
NGL, per barrel	15.63	-	-	-	36.28	-	35.76
Natural gas, per thousand cubic feet	1.75	-	5.01	-	5.24	-	5.17
Average production costs, per oil-equivalent barrel - total	28.17	-	14.04	-	2.03	-	5.16
Total							
Average production prices							
Crude oil, per barrel	55.08	59.39	63.41	65.64	62.27	61.08	60.73
NGL, per barrel	18.90	16.59	30.56	41.41	33.23	30.55	25.89
Natural gas, per thousand cubic feet	1.54	1.44	4.73	1.49	4.49	6.26	3.82

Bitumen, per barrel	-	36.25	-	-	-	-	36.25
Synthetic oil, per barrel	-	56.18	-	-	-	-	56.18
Average production costs, per oil-equivalent barrel - total	13.08	23.41	13.80	17.56	4.39	6.60	11.51
Average production costs, per barrel - bitumen	-	24.18	-	-	-	-	24.18
Average production costs, per barrel - synthetic oil	-	40.38	-	-	-	-	40.38
During 2018							
Consolidated Subsidiaries							
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
Equity Companies							
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
Total							
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

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2017				*(dollars per unit)*			
Consolidated Subsidiaries							
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
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

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

	2019	2018	2017
Net Productive Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	3	1	-
Canada/Other Americas	6	4	5
Europe	1	-	-
Africa	-	1	1
Asia	-	-	-
Australia/Oceania	1	1	-
Total Consolidated Subsidiaries	11	7	6
Equity Companies			
United States	-	-	-
Europe	-	-	-
Africa	-	-	-
Asia	-	-	-
Total Equity Companies	-	-	-
Total productive exploratory wells drilled	11	7	6
Net Dry Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	-	3	-
Canada/Other Americas	1	-	-
Europe	1	1	-
Africa	-	-	2

Asia	-	-	-
Australia/Oceania	1	2	-
Total Consolidated Subsidiaries	3	6	2
Equity Companies			
United States	-	-	-
Europe	-	-	-
Africa	-	-	-
Asia	-	-	1
Total Equity Companies	-	-	1
Total dry exploratory wells drilled	3	6	3

	2019	2018	2017
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
United States	618	389	300
Canada/Other Americas	49	32	12
Europe	3	3	6
Africa	4	1	6
Asia	12	14	15
Australia/Oceania	-	-	1
Total Consolidated Subsidiaries	686	439	340
Equity Companies			
United States	199	168	154
Europe	-	3	1
Africa	-	-	-
Asia	9	6	3
Total Equity Companies	208	177	158
Total productive development wells drilled	894	616	498
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	8	4	4
Canada/Other Americas	-	1	-
Europe	-	-	1
Africa	1	1	-
Asia	-	-	-
Australia/Oceania	-	-	-

Total Consolidated Subsidiaries	9	6	5
Equity Companies			
United States	-	-	-
Europe	-	-	-
Africa	-	-	-
Asia	-	-	-
Total Equity Companies	-	-	-
Total dry development wells drilled	9	6	5
Total number of net wells drilled	917	635	512

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 2019, the company's share of net production of synthetic crude oil was about 65 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 2019, average net production at Kearl was about 197 thousand barrels per day.

5. Present Activities

A. Wells Drilling

	Year-End 2019		Year-End 2018	
	Gross	**Net**	**Gross**	**Net**
Wells Drilling				
Consolidated Subsidiaries				
United States	1,133	704	997	491
Canada/Other Americas	27	20	41	32
Europe	16	7	13	3
Africa	4	1	5	1
Asia	46	14	50	14
Australia/Oceania	14	4	4	2
Total Consolidated Subsidiaries	1,240	750	1,110	543
Equity Companies				
United States	3	1	7	1

Europe	-	-	1	1
Africa	6	1	-	-
Asia	11	3	17	4
Total Equity Companies	20	5	25	6
Total gross and net wells drilling	1,260755		1,135549	

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2019 acreage holdings totaled 11.5 million net acres, of which 0.6 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska. The Golden Pass liquefied natural gas export project was funded in 2019.

During the year, 815.6 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 2019 was 0.5 million acres. A total of 0.9 net exploration and development wells were completed during the year.

Participation in Alaska production and development continued with a total of 11.6 net development wells completed.

CANADA / OTHER AMERICAS

Canada

Oil and Gas Operations: ExxonMobil's year-end 2019 acreage holdings totaled 6.8 million net acres, of which 3.9 million net acres were offshore. A total of 29.7 net development wells were completed during the year.

In Situ Bitumen Operations: ExxonMobil's year-end 2019 in situ bitumen acreage holdings totaled 0.6 million net onshore acres. A total of 14 net development wells at Cold Lake were completed during the year.

Argentina

ExxonMobil's net acreage totaled 2.9 million acres, of which 2.6 million net acres were offshore at year-end 2019. During the year, a total of 4.2 net exploration and development wells were completed. In 2019, ExxonMobil acquired approximately 2.6 million net acres in three offshore blocks located in the Malvinas Basin.

Guyana

ExxonMobil's net acreage totaled 4.6 million offshore acres at year-end 2019. During the year, 6.3 net exploration and development wells were completed. The Liza Phase 1 project started up in December 2019, and the Liza Phase 2 project was funded in 2019.

EUROPE

Germany

ExxonMobil's net acreage totaled 2.2 million onshore acres at year-end 2019. During the year, 0.7 net exploration and development wells were completed.

Netherlands

ExxonMobil's net interest in licenses totaled approximately 1.5 million acres, of which 1.1 million acres were onshore at year-end 2019. 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 in 2018 followed by the execution of additional implementation agreements. In 2019, the Dutch Cabinet informed Parliament of its intention to further reduce Groningen gas extraction and terminate production in 2022.

United Kingdom

ExxonMobil's net interest in licenses totaled approximately 0.3 million offshore acres at year-end 2019. During the year, a total of 0.4 net development wells were completed. Development activities continued on the Penguins Redevelopment project.

AFRICA

Angola

ExxonMobil’s net acreage totaled 0.2 million offshore acres at year-end 2019. During the year, a total of 1.3 net development wells were completed. On Block 32, the Kaombo Split Hub Sul floating production storage and offloading (FPSO) vessel started up in April 2019, and the Norte FPSO started up in 2018.

Chad

ExxonMobil’s net acreage holdings totaled 46 thousand onshore acres at year-end 2019.

Equatorial Guinea

ExxonMobil’s net acreage totaled 0.5 million offshore acres at year-end 2019. During the year, a total of 2.4 net development wells were completed.

Mozambique

ExxonMobil’s net acreage totaled approximately 1.8 million offshore acres at year-end 2019. In 2019, ExxonMobil relinquished approximately 0.8 million net acres as the Company reduced its working interest in Area 5 offshore blocks, Angoche A5-B, Zambezi Z5-C, and Zambezi Z5-D. Development activities continued on the Coral South Floating LNG project during the year.

Nigeria

ExxonMobil’s net acreage totaled 0.9 million offshore acres at year-end 2019. During the year, a total of 1.3 net exploration and development wells were completed.

ASIA

Azerbaijan

ExxonMobil's net acreage totaled 7 thousand offshore acres at year-end 2019. During the year, a total of 0.7 net development wells were completed.

Indonesia

ExxonMobil’s net acreage totaled 0.1 million onshore acres at year-end 2019. The Kedung Keris project started up in November 2019.

Iraq

ExxonMobil’s net acreage totaled 0.1 million onshore acres at year-end 2019. During the year, a total of 2.6 net development wells were completed at the West Qurna Phase I oil field. Oil field rehabilitation activities continued during 2019 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 0.3 million acres, of which 0.2 million net acres were offshore at year-end 2019. During the year, a total of 9.5 net development wells were completed. 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 2019.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil’s net acreage totaled 65 thousand acres offshore at year-end 2019. 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 during the year.

Russia

ExxonMobil's net acreage holdings in Sakhalin totaled 85 thousand offshore acres at year-end 2019. During the year, a total of 2.1 net development wells were completed.

Thailand

ExxonMobil's net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2019.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2019. During the year, a total of 5.3 net development wells were completed. Commissioning activities continued on the Upper Zakum 750 project, while development activities progressed on the Upper Zakum 1 MBD project.

AUSTRALIA / OCEANIA

Australia

ExxonMobil's net acreage totaled 1.8 million acres offshore and 10 thousand acres onshore at year-end 2019. During the year, a total of 1.0 net exploration well was completed in the Bass Strait. Development activities continued on the West Barracouta project during the year.

The co-venturer-operated Gorgon Jansz liquefied natural gas (LNG) development consists of a subsea infrastructure for offshore production and transportation of the gas, a 15.6 million tonnes per year LNG facility and a 280 million cubic feet per day domestic gas plant located on Barrow Island, Western Australia. Development activities continued on the Gorgon Stage 2 project during the year.

Papua New Guinea

ExxonMobil's net acreage totaled 6.9 million acres, of which 3.3 million net acres were offshore at year-end 2019. During the year, a total of 1.2 net exploration and development wells were completed. In 2019, ExxonMobil relinquished approximately 3 million net acres as the Company reduced its working interest, primarily in deepwater offshore licenses. 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.

WORLDWIDE EXPLORATION

At year-end 2019, 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 41.5 million net acres were held at year-end 2019 and 2.7 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 44 million barrels of oil and 2,500 billion cubic feet of natural gas for the period from 2020 through 2022. 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 purchases on the open market as necessary.

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

A. Gross and Net Productive Wells

	Year-End 2019				Year-End 2018			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	20,559	8,502	21,893	13,182	20,996	8,460	25,061	14,396
Canada/Other Americas	4,905	4,724	3,441	1,347	5,037	4,781	4,262	1,650
Europe	741	207	517	236	981	256	648	261
Africa	1,191	456	13	5	1,221	472	12	5
Asia	943	301	133	79	891	286	133	79
Australia/Oceania	582	120	87	36	577	123	81	33
Total Consolidated Subsidiaries	28,921	14,310	26,084	14,885	29,703	14,378	30,197	16,424
Equity Companies								
United States	12,947	5,328	4,500	577	13,126	5,398	4,503	577
Europe	57	20	561	175	57	20	602	187
Asia	194	49	126	30	164	41	126	30
Total Equity Companies	13,198	5,397	5,187	782	13,347	5,459	5,231	794
Total gross and net productive wells	42,119	19,707	31,271	15,667	43,050	19,837	35,428	17,218

There were 27,532 gross and 23,857 net operated wells at year-end 2019 and 28,847 gross and 24,696 net operated wells at year-end 2018. The number of wells with multiple completions was 1,023 gross in 2019 and 947 gross in 2018.

B. Gross and Net Developed Acreage

	Year-End 2019		Year-End 2018	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	13,283	8,097	13,900	8,399
Canada/Other Americas *(1)*	3,020	2,100	3,596	2,325
Europe	2,229	1,182	2,937	1,315
Africa	2,409	832	2,492	866
Asia	1,938	561	1,939	563
Australia/Oceania	3,262	1,068	3,262	1,068
Total Consolidated Subsidiaries	26,141	13,840	28,126	14,536
Equity Companies				
United States	926	207	929	208
Europe	4,069	1,280	4,110	1,287
Asia	628	155	628	155
Total Equity Companies	5,623	1,642	5,667	1,650
Total gross and net developed acreage	31,764	15,482	33,793	16,186

(1) Includes developed acreage in Other Americas of 472 gross and 295 net thousands of acres for 2019 and 375 gross and 244 net thousands of acres for 2018.

Separate acreage data for oil and gas are not maintained because, in many instances, both are produced from the same acreage.

C. Gross and Net Undeveloped Acreage

	Year-End 2019		Year-End 2018	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				

United States	7,123	3,146	7,421	3,427
Canada/Other Americas *(1)*	36,509	17,950	34,932	15,340
Europe	18,212	7,619	9,168	4,191
Africa	56,049	32,449	44,556	24,000
Asia	6,880	2,911	7,195	2,964
Australia/Oceania	14,773	7,689	15,337	10,756
Total Consolidated Subsidiaries	139,546	71,764	118,609	60,678
Equity Companies				
United States	189	73	203	76
Europe	366	105	100	25
Africa	596	149	596	149
Asia	73	5	73	5
Total Equity Companies	1,224	332	972	255
Total gross and net undeveloped acreage	140,770	72,096	119,581	60,933

(1) Includes undeveloped acreage in Other Americas of 25,327 gross and 12,065 net thousands of acres for 2019 and 23,872 gross and 9,595 net thousands of acres for 2018.

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 2014. Pursuant to the amended law, the production term for an onshore unconventional concession is 35 years, and 25 years for a conventional concession, with unlimited ten-year extensions possible, once a field has been developed. In 2019, the government granted three offshore exploration licenses, with terms of eight years, divided into two exploration periods of four years, with an optional extension of five years for each license. Three onshore exploration concessions were initially granted prior to the amendment and are governed under Provincial Law with expiration terms between 2020 and 2022.

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 and 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 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 subject to 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.

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 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 an approved plan of development becomes effective 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 to 20 percent of the contract area after three years and generally allow the contractor to retain no more than 50 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 between the Russian government and the Sakhalin-1 consortium, of which ExxonMobil is the operator.

Thailand

The Petroleum Act of 1971 allows production under ExxonMobil's concessions for 30 years with a ten-year extension at terms generally prevalent at the time. The term of one of the two concessions expires in 2021.

United Arab Emirates

An interest in the development and production activities of the offshore Upper Zakum 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 2019 *(1)*

			ExxonMobil Share KBD *(2)*	ExxonMobil Interest %
United States				
	Joliet	Illinois	236	100
	Baton Rouge	Louisiana	518	100
	Billings	Montana	60	100
	Baytown	Texas	561	100
	Beaumont	Texas	369	100
	Total United States		1,744	
Canada				
	Strathcona	Alberta	191	69.6
	Nanticoke	Ontario	113	69.6
	Sarnia	Ontario	119	69.6
	Total Canada		423	
Europe				
	Antwerp	Belgium	307	100
	Fos-sur-Mer	France	133	82.9
	Gravenchon	France	240	82.9
	Karlsruhe	Germany	78	25
	Trecate	Italy	132	75.3
	Rotterdam	Netherlands	192	100
	Slagen	Norway	116	100
	Fawley		262	100

	United Kingdom		
Total Europe		1,460	
Asia Pacific			
Altona	Australia	86	100
Fujian	China	67	25
Jurong/PAC	Singapore	592	100
Sriracha	Thailand	167	66
Total Asia Pacific		912	
Middle East			
Yanbu	Saudi Arabia	200	50
Total Worldwide		4,739	

(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 2019

United States	
Owned/leased	-
Distributors/resellers	10,830
Total United States	10,830
Canada	
Owned/leased	-
Distributors/resellers	2,175
Total Canada	2,175
Europe	
Owned/leased	197
Distributors/resellers	5,743
Total Europe	5,940
Asia Pacific	
Owned/leased	567
Distributors/resellers	1,134
Total Asia Pacific	1,701
Latin America	
Owned/leased	-
Distributors/resellers	348
Total Latin America	348
Middle East/Africa	

Owned/leased	225
Distributors/resellers	190
Total Middle East/Africa	415
Worldwide	
Owned/leased	989
Distributors/resellers	20,420
Total Worldwide	21,409

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 2019 *(1)*

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest %
		(millions of metric tons per year)				
North America						
Baton Rouge	Louisiana	1.1	1.3	0.4	-	100
Baytown	Texas	3.8	-	0.7	0.6	100
Beaumont	Texas	0.9	1.7	-	0.3	100
Mont Belvieu	Texas	-	2.3	-	-	100
Sarnia	Ontario	0.3	0.5	-	-	69.6
Total North America		6.1	5.8	1.1	0.9	
Europe						
Antwerp	Belgium	-	0.4	-	-	100
Fife	United Kingdom	0.4	-	-	-	50
Gravenchon	France	0.4	0.4	0.3	-	100
Meerhout	Belgium	-	0.5	-	-	100
Rotterdam	Netherlands	-	-	-	0.7	100
Total Europe		0.8	1.3	0.3	0.7	
Middle East						
Al Jubail	Saudi Arabia	0.6	0.7	-	-	50
Yanbu	Saudi Arabia	1.0	0.7	0.2	-	50
Total Middle East		1.6	1.4	0.2	-	

Asia Pacific						
Fujian	China	0.3	0.2	0.2	0.2	25
Singapore	Singapore	1.9	1.9	0.9	1.8	100
Sriracha	Thailand	-	-	-	0.5	66
Total Asia Pacific		2.2	2.1	1.1	2.5	
Total Worldwide		10.7	10.6	2.7	4.1	

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

ITEM 3. LEGAL PROCEEDINGS

Regarding a matter last reported in the Corporation's Form 10-Q for the third quarter of 2019, on December 31, 2019, the United States Federal District Court, Northern District of Texas (the Federal Court), vacated the civil penalty assessed by the United States Department of Treasury, Office of Foreign Assets Control (OFAC) against Exxon Mobil Corporation, ExxonMobil Development Company and ExxonMobil Oil Corporation on July 20, 2017, for allegedly violating the Ukraine-Related Sanctions Regulations, 31 C.F.R. part 589. The civil penalty vacated by the Federal Court was in the amount of $2,000,000. OFAC is currently determining whether to appeal the Federal Court's order to the 5th Circuit Court of Appeals.

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.

Information about our Executive Officers
(positions and ages as of February 26, 2020)

Darren W. Woods	*Chairman of the Board*	
Held current title since:	January 1, 2017	Age: 55

Mr. Darren W. Woods 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.

Neil A. Chapman	*Senior Vice President*	
Held current title since:	January 1, 2018	Age: 57

Mr. Neil A. Chapman 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.

Andrew P. Swiger	*Senior Vice President*	
Held current title since:	April 1, 2009	Age: 63

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.

Jack P. Williams, Jr.	*Senior Vice President*	
Held current title since:	June 1, 2014	Age: 56

Mr. Jack P. Williams, Jr. became Senior Vice President of Exxon Mobil Corporation on June 1, 2014, a position he continues to hold as of this filing date.

Linda D. DuCharme	*President, ExxonMobil Upstream Integrated Solutions Company*	
Held current title since:	April 1, 2019	Age: 55

Ms. Linda D. DuCharme was Vice President, Europe, Russia and Caspian for ExxonMobil Gas & Power Marketing Company February 1, 2011 – June 30, 2015. She was Vice President, Americas, Africa and Asia, ExxonMobil Gas & Power Marketing Company July 1, 2015 – July 31, 2016. She was President of ExxonMobil Global Services Company August 1, 2016 – March 31, 2019. She became President of ExxonMobil Upstream Integrated Solutions Company on April 1, 2019, a position she continues to hold as of this filing date.

Neil W. Duffin	*President, ExxonMobil Global Projects Company*	
Held current title since:	April 1, 2019	Age: 63

Mr. Neil W. Duffin was President of ExxonMobil Development Company April 13, 2007 – December 31, 2016. He was President of ExxonMobil Production Company and Vice President of Exxon Mobil Corporation January 1, 2017 – March 31, 2019. He became President of ExxonMobil Global Projects Company on April 1, 2019, a position he continues to hold as of this filing date.

Randall M. Ebner	*Vice President and General Counsel*	
Held current title since:	November 1, 2016	Age: 64

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.

Stephen M. Greenlee *Vice President*

Held current title since: September 1, 2010 Age: 62

Mr. Stephen M. Greenlee was President of ExxonMobil Exploration Company and Vice President of Exxon Mobil Corporation September 1, 2010 – March 31, 2019. He became President of ExxonMobil Upstream Business Development Company and Vice President of Exxon Mobil Corporation on April 1, 2019, positions he continues to hold as of this filing date.

Neil A. Hansen *Vice President – Investor Relations and Secretary*

Held current title since: July 1, 2018 Age: 45

Mr. Neil A. Hansen 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.

Liam M. Mallon *Vice President*

Held current title since: April 1, 2019 Age: 57

Mr. Liam M. Mallon was Executive Vice President, ExxonMobil Development Company February 1, 2014 – December 31, 2016. He was President of ExxonMobil Development Company January 1, 2017 – March 31, 2019. He became President of ExxonMobil Upstream Oil & Gas Company and Vice President of Exxon Mobil Corporation on April 1, 2019, positions he continues to hold as of this filing date.

Karen T. McKee *Vice President*

Held current title since: April 1, 2019 Age: 53

Ms. Karen T. McKee was Vice President, Basic Chemicals, ExxonMobil Chemical Company. May 1, 2014 – July 31, 2017. She was Senior Vice President, Basic Chemicals, Integration & Growth, ExxonMobil Chemical Company August 1, 2017 – March 31, 2019. She became President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation on April 1, 2019, positions she continues to hold as of this filing date.

Bryan W. Milton *Vice President*

Held current title since: August 1, 2016 Age: 55

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.

David S. Rosenthal *Vice President and Controller*

Held current title since: October 1, 2008 (Vice President)
September 1, 2014 (Controller) Age: 63

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.

Robert N. Schleckser *Vice President and Treasurer*

Held current title since: May 1, 2011 Age: 63

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.

James M. Spellings, Jr. *Vice President and General Tax Counsel*

Held current title since: March 1, 2010 Age: 58

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.

Theodore J. Wojnar, Jr. *Vice President – Corporate Strategic Planning*

Held current title since: August 1, 2017 Age: 60

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, 2019

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 2019	-		-	
November 2019	-		-	
December 2019	-		-	
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,				
	2019	2018	2017	2016	2015
	(millions of dollars, except per share amounts)				

Sales and other operating revenue	255,583	279,332	237,162	200,628	239,854
Net income attributable to ExxonMobil	14,340	20,840	19,710	7,840	16,150
Earnings per common share	3.36	4.88	4.63	1.88	3.85
Earnings per common share - assuming dilution	3.36	4.88	4.63	1.88	3.85
Cash dividends per common share	3.43	3.23	3.06	2.98	2.88
Total assets	362,597	346,196	348,691	330,314	336,758
Long-term debt	26,342	20,538	24,406	28,932	19,925

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 26, 2020, beginning with the section entitled “Report of Independent Registered Public Accounting Firm” and continuing through “Note 20: Sale of Norway Assets”;
- “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, 2019. 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, 2019.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation’s internal control over financial reporting as of December 31, 2019, 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 “Information about our Executive Officers”.

Incorporated by reference to the following from the registrant’s definitive proxy statement for the 2020 annual meeting of shareholders (the “2020 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 2020 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 2020 Proxy Statement.

Equity Compensation Plan Information

Plan Category	*(a)* Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	*(b)* Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	*(c)* Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
	42,636,850 *(1)*	-	76,488,320 *(2)(3)*

Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders	-	-	-
Total	42,636,850	-	76,488,320

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

(2) Available shares can be granted in the form of restricted stock or other stock-based awards. Includes 76,036,620 shares available for award under the 2003 Incentive Program and 451,700 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 2020 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 2020 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

Financial	Earnings After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
	2019	2018	2019	2018	2019	2018	2019	2018
	(millions of dollars)				(percent)		(millions of dollars)	
Upstream								
United States	536	1,739	72,152	69,981	0.7	2.5	11,653	7,670
Non-U.S.	13,906	12,340	107,271	107,893	13.0	11.4	11,832	12,524
Total	14,442	14,079	179,423	177,874	8.0	7.9	23,485	20,194
Downstream								
United States	1,717	2,962	9,515	8,725	18.0	33.9	2,353	1,186
Non-U.S.	606	3,048	18,518	17,015	3.3	17.9	2,018	2,243
Total	2,323	6,010	28,033	25,740	8.3	23.3	4,371	3,429
Chemical								
United States	206	1,642	13,196	12,171	1.6	13.5	2,547	1,747
Non-U.S.	386	1,709	18,113	18,249	2.1	9.4	718	488
Total	592	3,351	31,309	30,420	1.9	11.0	3,265	2,235
Corporate and financing	(3,017)	(2,600)	(2,162)	(1,660)	-	-	27	65
Total	14,340	20,840	236,603	232,374	6.5	9.2	31,148	25,923

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

Operating	2019	2018		2019	2018
	(thousands of barrels daily)			(thousands of barrels daily)	
Net liquids production			Refinery throughput		
United States	646	551	United States	1,532	1,588

Non-U.S.	1,740	1,715
Total	2,386	2,266

	(millions of cubic feet daily)	
Natural gas production available for sale		
United States	2,778	2,574
Non-U.S.	6,616	6,831
Total	9,394	9,405

	(thousands of oil-equivalent barrels daily)	
Oil-equivalent production *(1)*	3,952	3,833

Non-U.S.	2,449	2,684
Total	3,981	4,272

	(thousands of barrels daily)	
Petroleum product sales *(2)*		
United States	2,292	2,210
Non-U.S.	3,160	3,302
Total	5,452	5,512

	(thousands of metric tons)	
Chemical prime product sales *(2) (3)*		
United States	9,127	9,824
Non-U.S.	17,389	17,045
Total	26,516	26,869

(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

	2019	2018	2017	2016	2015
	(millions of dollars, except where stated otherwise)				
Sales and other operating revenue	255,583	279,332	237,162	200,628	239,854
Earnings					
Upstream	14,442	14,079	13,355	196	7,101
Downstream	2,323	6,010	5,597	4,201	6,557
Chemical	592	3,351	4,518	4,615	4,418
Corporate and financing	(3,017)	(2,600)	(3,760)	(1,172)	(1,926)
Net income attributable to ExxonMobil	14,340	20,840	19,710	7,840	16,150
Earnings per common share (dollars)	3.36	4.88	4.63	1.88	3.85
Earnings per common share – assuming dilution (dollars)	3.36	4.88	4.63	1.88	3.85
Earnings to average ExxonMobil share of equity (percent)	7.5	11.0	11.1	4.6	9.4
Working capital	(13,937)	(9,165)	(10,637)	(6,222)	(11,353)
Ratio of current assets to current liabilities (times)	0.78	0.84	0.82	0.87	0.79
Additions to property, plant and equipment	24,904	20,051	24,901	16,100	27,475
Property, plant and equipment, less allowances	253,018	247,101	252,630	244,224	251,605
Total assets	362,597	346,196	348,691	330,314	336,758
Exploration expenses, including dry holes	1,269	1,466	1,790	1,467	1,523
Research and development costs	1,214	1,116	1,063	1,058	1,008

Long-term debt	26,342	20,538	24,406	28,932	19,925
Total debt	46,920	37,796	42,336	42,762	38,687
Debt to capital (percent)	19.1	16.0	17.9	19.7	18.0
Net debt to capital (percent) *(1)*	18.1	14.9	16.8	18.4	16.5
ExxonMobil share of equity at year-end	191,650	191,794	187,688	167,325	170,811
ExxonMobil share of equity per common share (dollars)	45.26	45.27	44.28	40.34	41.10
Weighted average number of common shares					
outstanding (millions)	4,270	4,270	4,256	4,177	4,196
Number of regular employees at year-end (thousands) *(2)*	74.9	71.0	69.6	71.1	73.5

(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.

Cash flow from operations and asset sales	**2019**	**2018**	**2017**
		(millions of dollars)	
Net cash provided by operating activities	29,716	36,014	30,066
Proceeds associated with sales of subsidiaries, property, plant and equipment,			
and sales and returns of investments	3,692	4,123	3,103
Cash flow from operations and asset sales	33,408	40,137	33,169

Capital Employed

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

Capital employed	**2019**	**2018**	**2017**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	362,597	346,196	348,691
Less liabilities and noncontrolling interests share of assets and liabilities			

Total current liabilities excluding notes and loans payable	(43,411)	(39,880)	(39,841)
Total long-term liabilities excluding long-term debt	(73,328)	(69,992)	(72,014)
Noncontrolling interests share of assets and liabilities	(8,839)	(7,958)	(8,298)
Add ExxonMobil share of debt-financed equity company net assets	3,906	3,914	3,929
Total capital employed	240,925	232,280	232,467

Total corporate sources: debt and equity perspective			
Notes and loans payable	20,578	17,258	17,930
Long-term debt	26,342	20,538	24,406
ExxonMobil share of equity	191,650	191,794	187,688
Less noncontrolling interests share of total debt	(1,551)	(1,224)	(1,486)
Add ExxonMobil share of equity company debt	3,906	3,914	3,929
Total capital employed	240,925	232,280	232,467

FREQUENTLY USED TERMS

Return on Average Capital Employed

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

Return on average capital employed	**2019**	**2018**	**2017**
		(millions of dollars)	
Net income attributable to ExxonMobil	14,340	20,840	19,710
Financing costs (after tax)			
Gross third-party debt	(1,075)	(912)	(709)
ExxonMobil share of equity companies	(207)	(192)	(204)
All other financing costs – net	141	498	515
Total financing costs	(1,141)	(606)	(398)
Earnings excluding financing costs	15,481	21,446	20,108
Average capital employed	236,603	232,374	222,631
Return on average capital employed – corporate total	6.5%	9.2%	9.0%

QUARTERLY INFORMATION

	2019					2018				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Year**	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Year**
Volumes										
Production of crude oil,	*(thousands of barrels daily)*									
natural gas liquids,	2,327	2,389	2,392	2,436	2,386	2,216	2,212	2,286	2,348	2,266
synthetic oil and bitumen										
Refinery throughput	3,886	3,930	4,052	4,053	3,981	4,293	4,105	4,392	4,298	4,272
Petroleum product sales *(1)*	5,415	5,408	5,504	5,482	5,452	5,432	5,502	5,616	5,495	5,512
Natural gas production	*(millions of cubic feet daily)*									
available for sale	9,924	9,120	9,045	9,495	9,394	10,038	8,613	9,001	9,974	9,405
	(thousands of oil-equivalent barrels daily)									
Oil-equivalent production *(2)*	3,981	3,909	3,899	4,018	3,952	3,889	3,647	3,786	4,010	3,833
	(thousands of metric tons)									
Chemical prime product sales *(1)*	6,772	6,699	6,476	6,569	26,516	6,668	6,852	6,677	6,672	26,869
Summarized financial data										
Sales and other operating	*(millions of dollars)*									
revenue	61,646	67,491	63,422	63,024	255,583	65,436	71,456	74,187	68,253	279,332
Gross profit *(3)*	13,304	14,396	14,411	13,847	55,958	16,187	16,622	18,656	16,268	67,733
Net income attributable to										
ExxonMobil *(4)*	2,350	3,130	3,170	5,690	14,340	4,650	3,950	6,240	6,000	20,840

Per share data					*(dollars per share)*					
Earnings per common share *(5)*	0.55	0.73	0.75	1.33	3.36	1.09	0.92	1.46	1.41	4.88
Earnings per common share										
– assuming dilution *(5)*	0.55	0.73	0.75	1.33	3.36	1.09	0.92	1.46	1.41	4.88

(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.

(4) Fourth quarter 2019 included a gain of $3,655 million on the sale of non-operated upstream assets in Norway.

(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 354,828 registered shareholders of ExxonMobil common stock at December 31, 2019. At January 31, 2020, the registered shareholders of ExxonMobil common stock numbered 352,585.

On January 29, 2020, the Corporation declared an $0.87 dividend per common share, payable March 10, 2020.

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

FUNCTIONAL EARNINGS	2019	2018	2017
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	536	1,739	6,622
Non-U.S.	13,906	12,340	6,733
Downstream			
United States	1,717	2,962	1,948
Non-U.S.	606	3,048	3,649
Chemical			
United States	206	1,642	2,190
Non-U.S.	386	1,709	2,328
Corporate and financing	(3,017)	(2,600)	(3,760)
Net income attributable to ExxonMobil (U.S. GAAP)	14,340	20,840	19,710
Earnings per common share	3.36	4.88	4.63
Earnings per common share – assuming dilution	3.36	4.88	4.63

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 related to outlooks, projections, goals, targets, descriptions of strategic plans and objectives, and other statements of future events or conditions are forward-looking statements. Actual future results, including business and project plans, capacities, costs, and timing; capital spending; proceeds from asset sales; resource recoveries and production rates; asset carrying values; proved reserves; financing sources; the resolution of contingencies and uncertain tax positions; and the impact of new technologies, including to increase capital efficiency and production and to reduce greenhouse gas emissions, could differ materially due to a number of factors. These include global or regional changes in supply and demand for oil, gas, petrochemicals, feedstocks and other market conditions that impact prices and differentials; reservoir performance; the outcome of exploration projects and timely completion of development and construction projects; the impact of fiscal and commercial terms and the outcome of commercial negotiations or acquisitions; changes in law, taxes, or regulation including environmental regulations, and timely granting of governmental permits; war, trade agreements, shipping blockades or harassment, and other political, public health or security disturbances; opportunities for and regulatory approval of potential investments or divestments; the actions of competitors; the capture of efficiencies between business lines; unforeseen technical or operating difficulties; unexpected technological developments; the ability to bring new technologies to commercial scale on a cost-competitive basis, including large-scale hydraulic fracturing projects; general economic conditions including the occurrence and duration of economic recessions; the results of research programs; and other factors discussed herein and in Item 1A. Risk Factors. We assume no duty to update these statements as of any future date. 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 2019 *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 1.6 billion more than in 2017. 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 20 percent from 2017 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 products 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 2017 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 2017, in part as a result of policies to improve air quality as well as reduce greenhouse gas emissions to address the risks related to climate change. From 2017 to 2040, the amount of electricity supplied using natural gas, nuclear power, and renewables is likely to grow by two thirds, accounting for the entire growth in electricity supplies and offsetting the reduction of coal. 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 75 percent of the increase in electricity supplies worldwide through 2040. Total renewables will likely reach nearly 40 percent of global electricity supplies by 2040. Natural gas and nuclear are also expected to increase shares over the period to 2040, reaching almost 30 percent and about 15 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 and policy developments.

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase more than 25 percent from 2017 to 2040. Transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period. Light-duty vehicle demand for liquid fuels is projected to peak prior to 2025 and then decline to levels seen in the early-2010s by 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 70 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 114 million barrels of oil equivalent per day, an increase of about 16 percent from 2017. 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 and lower carbon supply options. However, timely investments will remain critical to meeting global needs with reliable and affordable supplies.

Natural gas is a low-emission, versatile and practical fuel for a wide variety of applications, and it is expected to grow the most of any primary energy type from 2017 to 2040, meeting more than 40 percent of global energy demand growth. Global natural gas demand is expected to rise about 35 percent from 2017 to 2040, with about half of that increase coming from 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 60 percent of the growth in natural gas supplies is expected to be from unconventional sources. At the same time, conventionally-produced natural gas is likely to remain the cornerstone of global supply, meeting more than two thirds of worldwide demand in 2040. Liquefied natural gas (LNG) trade will expand significantly, meeting about 40 percent 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 30 percent 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 about 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 2017 to 2040, when they will likely be just over 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 as the International Energy Agency (IEA) describes in its *World Energy Outlook 2019*. According to the IEA's Stated Energy Policies Scenario, the investment required to meet oil and natural gas supply requirements worldwide over the period 2019-2040 will be about $20 trillion (measured in 2018 dollars). In the IEA's Sustainable Development Scenario, which is in line with the objectives of the Paris Agreement on climate change, the investment need would still accumulate to $13 trillion.

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_2 emissions is assumed to reach about $80 per tonne 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 in addition to 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 nearly half of global production, and is expected to grow to be about 60 percent 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 2019, the Upstream business produced 4.0 million oil-equivalent barrels per day. The Corporation continued to have exploration success in Guyana and Cyprus, and also made strategic acreage acquisitions in Argentina, Brazil, Greece, Egypt, and Namibia. In the more mature conventional operations, our primary goal is to maximize cash flow generation through ExxonMobil's world-class workforce and best practices in reliability and project execution. As a result, assets in Russia, Indonesia, Kazakhstan, and the United Arab Emirates all recorded their highest daily production rates to-date.

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 129 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 grew 1 million barrels per day or about 1 percent in 2019, but was outpaced by global refining capacity, which expanded by about 1.8 million barrels per day, resulting in weaker refining margins. Canadian crude differentials narrowed in 2019 as Alberta imposed limits on crude production, which resulted in lower refinery margins in Canada and the Midwest region of the U.S. New pipeline capacity in the Permian reduced the crude differentials between Midland and Houston. In the near term, we expect to continue to see variability in refining margins following the dynamics of the supply/demand balance.

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.

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. The three key projects that started up at the end of 2018 (Antwerp coker, Rotterdam advanced hydrocracker and Beaumont hydrofiner) have added incremental earnings in 2019 to the Downstream by upgrading resid and intermediates into high value clean products and basestocks. Four other strategic projects have been approved during the first half of 2019. The Singapore resid upgrade project will use proprietary technology to upgrade the resid streams from the refinery and chemical plant into clean fuels and basestocks; the Fawley hydrofiner will upgrade high sulfur distillates into finished diesel and the project will also strengthen the logistics into the UK market; the Beaumont light crude expansion will enable the site to increase the processing capability of advantaged tight oil crudes; and finally, the Wink to Webster pipeline will provide efficient transportation of more than 1 million barrels per day of crude oil from the Permian to the Houston refining center.

ExxonMobil continues to grow its product sales in new markets near major production assets with continued progress on the Mexico and Indonesia market entries. 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 motor oils.

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 chemical products continued to grow in 2019. Polyolefin and aromatics product margins were however further impacted by 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 by 2030, driven by continued global growth of the middle class. ExxonMobil's integration with refining, together with unparalleled project execution capacity, enhances our ability to generate industry-leading returns across a range of market environments.

These competitive advantages enable us to continue to invest in projects that are robust to the chemical market cycles. In 2019, we started up the expansion of the polyethylene plant in Beaumont, Texas ahead of schedule, capitalizing on advantaged feedstock and energy supplies in North America. This capacity, together with the world-scale Baytown polyethylene lines started up in 2017, help to meet the rapidly growing global demand for performance polymers. We also made full funding decisions for a suite of Chemical projects. A 450-thousand-tonnes-per-year performance polypropylene line will add to our existing polypropylene capacity in Baton Rouge. The Baytown Chemical Expansion Project broke ground in 2019, and includes a 400-thousand-tonnes-per-year *Vistamaxx* performance polymer unit and a 350-thousand-tonnes-per-year linear alpha olefins unit, further expanding ExxonMobil's product portfolio. Construction also began in San Patricio County, Texas on our joint venture ethane cracker and associated derivative units. In addition, we continued to progress plans for a world-scale steam cracker and performance derivative units in Guangdong Province, China.

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

REVIEW OF 2019 AND 2018 RESULTS

	2019	2018	2017
		(millions of dollars)	
Earnings (U.S. GAAP)			
Net income attributable to ExxonMobil (U.S. GAAP)	14,340	20,840	19,710

Upstream

	2019	2018	2017
		(millions of dollars)	
Upstream			
United States	536	1,739	6,622
Non-U.S.	13,906	12,340	6,733
Total	14,442	14,079	13,355

2019

Upstream earnings were $14,442 million, up $363 million from 2018.

- Lower realizations reduced earnings by $2.7 billion.
- Favorable volume and mix effects increased earnings by $860 million.
- All other items increased earnings by $2.2 billion, as a $3.7 billion gain from the Norway non-operated divestment was partly offset by higher expenses of $1.1 billion.
- U.S. Upstream earnings were $536 million and included asset impairments of $146 million.
- Non-U.S. Upstream earnings were $13,906 million, including the $3.7 billion gain from the Norway non-operated divestment.
- On an oil-equivalent basis, production of 4.0 million barrels per day was up 3 percent compared to 2018.
- Liquids production of 2.4 million barrels per day increased 120,000 barrels per day reflecting growth and higher entitlements.
- Natural gas production of 9.4 billion cubic feet per day decreased 11 million cubic feet per day from 2018, with the impact from divestments and higher downtime offset by growth and higher entitlements.

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.

Upstream Additional Information

	2019	2018
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production) *(1)*		
Prior Year	3,833	3,985
Entitlements - Net Interest	(1)	(3)
Entitlements - Price / Spend / Other	34	(68)
Quotas	-	-
Divestments	(27)	(58)
Growth / Other	113	(23)
Current Year	3,952	3,833

(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.

Downstream

	2019	2018	2017
		(millions of dollars)	
Downstream			
United States	1,717	2,962	1,948
Non-U.S.	606	3,048	3,649
Total	2,323	6,010	5,597

2019

Downstream earnings of $2,323 million decreased $3,687 million from 2018.

- Margins decreased earnings by $3 billion including the impact of lower North American crude differentials.
- Volume and mix effects lowered earnings by $50 million as project contributions and portfolio improvement were more than offset by increased downtime/maintenance and unfavorable yield/sales mix.
- All other items decreased earnings by $660 million, mainly driven by the absence of prior year divestment gains and higher expenses reflecting increased maintenance and project startups, partly offset by favorable foreign exchange impacts and LIFO inventory gains.
- U.S. Downstream earnings were $1,717 million, compared to $2,962 million in the prior year.
- Non-U.S. Downstream earnings were $606 million, compared to $3,048 million in the prior year.
- Petroleum product sales of 5.5 million barrels per day were 60,000 barrels per day lower than 2018.

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.

Chemical

	2019	2018	2017
		(millions of dollars)	
Chemical			
United States	206	1,642	2,190
Non-U.S.	386	1,709	2,328
Total	592	3,351	4,518

2019

Chemical earnings of $592 million decreased $2,759 million from 2018.

- Weaker margins decreased earnings by $1.8 billion.
- Volume and mix effects were essentially flat, as lower sales volumes were offset by new asset contributions.
- All other items decreased earnings by $940 million, primarily due to higher expenses associated with new assets, business growth, and maintenance activity, the absence of a favorable tax item in the prior year, and unfavorable foreign exchange impacts.
- U.S. Chemical earnings were $206 million in 2019, compared with $1,642 million in the prior year.
- Non-U.S. Chemical earnings were $386 million, compared with $1,709 million in the prior year.
- Prime product sales of 26.5 million metric tons were down 0.4 million metric tons from 2018.

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.

Corporate and Financing

	2019	2018	2017
		(millions of dollars)	

Corporate and financing	(3,017)	(2,600)	(3,760)

2019

Corporate and financing expenses were $3,017 million in 2019 compared to $2,600 million in 2018, with the increase mainly due to unfavorable tax impacts and higher financing costs.

2018

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

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2019	2018	2017
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	29,716	36,014	30,066
Investing activities	(23,084)	(16,446)	(15,730)
Financing activities	(6,618)	(19,446)	(15,130)
Effect of exchange rate changes	33	(257)	314
Increase/(decrease) in cash and cash equivalents	47	(135)	(480)
		(December 31)	
Total cash and cash equivalents	3,089	3,042	3,177

Total cash and cash equivalents were $3.1 billion at the end of 2019, up $47 million from the prior year. The major sources of funds in 2019 were net income including noncontrolling interests of $14.8 billion, the adjustment for the noncash provision of $19.0 billion for depreciation and depletion, a net debt increase of $8.7 billion, and proceeds from asset sales of $3.7 billion. The major uses of funds included spending for additions to property, plant and equipment of $24.4 billion, dividends to shareholders of $14.7 billion, and additional investments and advances of $3.9 billion.

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.

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. Commercial paper is used to balance short-term liquidity requirements, and is reflected in "Notes and loans payable" on the Consolidated Balance Sheet with changes in outstanding commercial paper between periods included in the Consolidated Statement of Cash Flows. On December 31, 2019, the Corporation had unused committed short-term lines of credit of $7.9 billion and unused committed long-term lines of credit of $0.2 billion. Cash that may be 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. 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. In particular, the Corporation's key tight-oil plays have higher initial decline rates which tend to moderate over time. 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 2019 were $31.1 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment level of up to $33 billion in 2020.

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.

The Corporation, as part of its ongoing asset management program, continues to evaluate its mix of assets for potential upgrade. Because of the ongoing nature of this program, dispositions will continue to be made from time to time which will result in either gains or losses. Additionally, the Corporation continues to evaluate opportunities to enhance its business portfolio through acquisitions of assets or companies, and enters into such transactions from time to time. Key criteria for evaluating acquisitions include potential for future growth and attractive current valuations. Acquisitions may be made with cash, shares of the Corporation's common stock, or both.

ExxonMobil closely monitors the potential impacts of Brexit and Interbank Offered Rate (IBOR) reforms, including LIBOR, 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

2019

Cash provided by operating activities totaled $29.7 billion in 2019, $6.3 billion lower than 2018. The major source of funds was net income including noncontrolling interests of $14.8 billion, a decrease of $6.6 billion. The noncash provision for depreciation and depletion was $19.0 billion, up $0.3 billion from the prior year. The adjustment for the net gain on asset sales was $1.7 billion, a decrease of $0.3 billion. The adjustment for dividends received less than equity in current earnings of equity companies was a reduction of $0.9 billion, compared to a reduction of $1.7 billion in 2018. Changes in operational working capital, excluding cash and debt, increased cash in 2019 by $0.9 billion.

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.

Cash Flow from Investing Activities

2019

Cash used in investing activities netted to $23.1 billion in 2019, $6.6 billion higher than 2018. Spending for property, plant and equipment of $24.4 billion increased $4.8 billion from 2018. Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments of $3.7 billion compared to $4.1 billion in 2018. Additional investments and advances were $1.9 billion higher in 2019, while proceeds from other investing activities including collection of advances increased by $0.5 billion.

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.

Cash Flow from Financing Activities

2019

Cash used in financing activities was $6.6 billion in 2019, $12.8 billion lower than 2018. Dividend payments on common shares increased to $3.43 per share from $3.23 per share and totaled $14.7 billion. During the third quarter of 2019, the Corporation issued $7.0 billion of long-term debt. Total debt increased $9.1 billion to $46.9 billion at year-end.

ExxonMobil share of equity decreased $0.1 billion to $191.7 billion. The addition to equity for earnings was $14.3 billion. This was offset by reductions for distributions to ExxonMobil shareholders of $14.7 billion, all in the form of dividends. Foreign exchange translation effects of $1.4 billion for the weaker U.S. currency increased equity, while a $1.4 billion change in the funded status of the postretirement benefits reserves reduced equity.

During 2019, 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 4,237 million to 4,234 million at the end of 2019.

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.

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, 2019. The table combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

		Payments Due by Period				
Commitments	**Note Reference Number**	**2020**	**2021-2022**	**2023-2024**	**2025 and Beyond**	**Total**
			(millions of dollars)			
Long-term debt excluding finance lease obligations *(1)*	6, 14	1,617	6,119	3,391	15,162	26,289
Asset retirement obligations *(2)*	9	1,001	1,027	806	8,446	11,280
Pension and other postretirement obligations *(3)*	17	2,332	1,777	1,735	16,169	22,013
Lease commitments *(4)*	11					
Operating and finance leases - commenced		1,632	2,468	1,313	2,188	7,601
Operating and finance leases - not yet commenced		327	569	1,046	2,627	4,569
Take-or-pay and unconditional purchase obligations *(5)*		3,836	7,093	5,580	17,148	33,657
Firm capital commitments *(6)*		10,982	5,278	1,149	686	18,095

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 $8.8 billion as of December 31, 2019, 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) The amount due in 2020 is included in Notes and loans payable of $20,578 million. The amounts due 2021 and beyond are included in Long-term debt of $26,342 million.

(2) Asset retirement obligations are primarily upstream asset removal costs at the completion of field life.

(3) The amount by which the benefit obligations exceeded the fair value of fund assets for 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 2020 and estimated benefit payments for unfunded plans in all years.

(4) Commitments for operating and finance leases cover drilling equipment, tankers and other assets.

(5) 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 obligations mainly pertain to pipeline, manufacturing supply and terminal agreements.

(6) 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 $18.1 billion, including $8.7 billion in the U.S.

Firm capital commitments for the non-U.S. Upstream of $6.9 billion were primarily associated with projects in Angola, Malaysia, Guyana, United Kingdom, Australia, United Arab Emirates, Canada and Brazil. The Corporation expects to fund the majority of these commitments with internally generated funds, supplemented by short-term and long-term debt as required.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2019, 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, 2019, the Corporation's unused short-term committed lines of credit totaled $7.9 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.

	2019	2018	2017
Debt to capital (percent)	19.1	16.0	17.9
Net debt to capital (percent)	18.1	14.9	16.8

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

Capital and exploration expenditures (Capex) represents the combined total of additions at cost to property, plant and equipment, and exploration expenses on a before-tax basis from the Consolidated Statement of Income. ExxonMobil's Capex includes its share of similar costs for equity companies. Capex excludes assets acquired in nonmonetary exchanges, the value of ExxonMobil shares used to acquire assets, and depreciation on the cost of exploration support equipment and facilities recorded to property, plant and equipment when acquired. While ExxonMobil's management is responsible for all investments and elements of net income, particular focus is placed on managing the controllable aspects of this group of expenditures.

	2019			2018		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total

		(millions of dollars)				
Upstream *(1)*	11,653	11,832	23,485	7,670	12,524	20,194
Downstream	2,353	2,018	4,371	1,186	2,243	3,429
Chemical	2,547	718	3,265	1,747	488	2,235
Other	27	-	27	65	-	65
Total	16,580	14,568	31,148	10,668	15,255	25,923

(1) Exploration expenses included.

Capex in 2019 was $31.1 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 up to $33 billion in 2020. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $23.5 billion in 2019 was up 16 percent from 2018. Investments in 2019 included growth in the U.S. Permian Basin and key development projects in Guyana and Mozambique. 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 66 percent of total proved reserves at year-end 2019, and has been over 60 percent for the last ten years.

Capital investments in the Downstream totaled $4.4 billion in 2019, an increase of $0.9 billion from 2018, reflecting global project spending. Chemical capital expenditures of $3.3 billion, increased $1 billion, representing investments in growth projects.

TAXES

	2019	2018	2017
		(millions of dollars)	
Income taxes	5,282	9,532	(1,174)
Effective income tax rate	*34%*	*37%*	*5%*
Total other taxes and duties	33,186	35,230	32,459
Total	38,468	44,762	31,285

2019

Total taxes on the Corporation's income statement were $38.5 billion in 2019, a decrease of $6.3 billion from 2018. Income tax expense, both current and deferred, was $5.3 billion compared to $9.5 billion in 2018. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 34 percent compared to 37 percent in the prior year due primarily to the impact of the divestment of non-operated upstream assets in Norway. Total other taxes and duties of $33.2 billion in 2019 decreased $2.0 billion.

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.

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 tax regulations issued by the U.S. Treasury. The Corporation 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) during 2018.

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

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2019	2018
	(millions of dollars)	
Capital expenditures	1,276	1,294
Other expenditures	3,969	3,558
Total	5,245	4,852

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 2019 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $5.2 billion, of which $4.0 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $5.9 billion in 2020 and 2021. Capital expenditures are expected to account for approximately 35 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 2019 for environmental liabilities were $290 million ($330 million in 2018) and the balance sheet reflects liabilities of $835 million as of December 31, 2019, and $875 million as of December 31, 2018.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2019	2018	2017
Crude oil and NGL ($ per barrel)	56.32	62.79	48.91
Natural gas ($ per thousand cubic feet)	3.05	3.87	3.04

(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 $475 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 $175 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. Refer to Note 18 for additional information on intersegment revenue.

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 currency and interest rate derivatives, none of which are material to the Corporation's financial position as of December 31, 2019 and 2018, or results of operations for the years ended 2019, 2018 and 2017. 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 generally expected to cover financial requirements, supplemented by long-term and short-term debt as required. Commercial paper is used to balance short-term liquidity requirements. 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 use of these 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, 2020, the Corporation adopted the Financial Accounting Standards Board’s update, *Financial Instruments – Credit Losses (Topic 326)*, as amended. The standard requires a valuation allowance for credit losses be recognized for certain financial assets that reflects the current expected credit loss over the asset’s contractual life. The valuation allowance considers the risk of loss, even if remote, and considers past events, current conditions and expectations of the future. The standard is not expected to have a material impact on the Corporation’s financial statements.

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, development and production costs, 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 and Resources 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 66 percent of total proved reserves at year-end 2019 (including both consolidated and equity company reserves), a decrease from 68 percent in 2018, 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.

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.

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, profitability reviews and other periodic control processes 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 development 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.

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.

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. 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 including price differentials, refining and chemical margins, volumes, development and operating costs, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. 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's 2019 results include after-tax charges of $0.1 billion to reduce the carrying value of assets to fair value. The assessment of fair value requires 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 value include 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 which are reflective of 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.

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 90 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 2019 was 5.3 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 9 percent and 6 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 $180 million before tax.

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

Litigation Contingencies

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

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

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

Tax Contingencies

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

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

Foreign Currency Translation

The method of translating the foreign currency financial statements of the Corporation's international subsidiaries into U.S. dollars is prescribed by 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, 2019.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2019, as stated in their report included in the Financial Section of this report.

Picture 4	Picture 1	_x0000_i1025
Darren W. Woods	Andrew P. Swiger	David S. Rosenthal
Chief Executive Officer	Senior Vice President	Vice President and Controller
	(Principal Financial Officer)	(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Picture 1

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 sheet of Exxon Mobil Corporation and its subsidiaries (the “Corporation”) as of December 31, 2019 and 2018, 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, 2019, 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, 2019 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 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, 2019, 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.

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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Oil and Natural Gas Reserves on Upstream Property, Plant and Equipment, Net

As described in Notes 1, 9 and 18 to the consolidated financial statements, the Corporation's consolidated upstream property, plant and equipment (PP&E) balance, net was $197 billion as of December 31, 2019, and the related depreciation, depletion and amortization (DD&A) expense for the year ended December 31, 2019 was $15 billion. Management uses the successful efforts method to account for its exploration and production activities. Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) are capitalized when incurred. As disclosed by management, proved oil and natural gas reserve quantities are used as the basis to calculate unit-of-production depreciation rates for most upstream assets. The estimation of proved oil and natural gas reserves is an ongoing process based on technical evaluations, commercial and market assessments, and detailed analysis of well information such as flow rates and reservoir pressure declines, development and production costs, among other factors. Reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals, assisted by the Global Reserves and Resources Group (together "management's specialists").

The principal consideration for our determination that performing procedures relating to the impact of proved oil and natural gas reserves on upstream PP&E, net is a critical audit matter is that there was significant judgment by management, including the use of management's specialists, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating evidence obtained related to the significant assumptions used by management, including development costs and production volumes.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and natural gas reserves and the calculation of DD&A expense. These procedures also included, among others (i) testing the completeness, accuracy, and relevance of underlying data used in developing management's estimates, (ii) evaluating the methods and significant assumptions used by management in developing these estimates, including development costs and production volumes, and (iii) testing the unit-of-production rates used to calculate DD&A expense. Evaluating the significant assumptions relating to the estimates of proved oil and natural gas reserves also involved obtaining evidence to support the reasonableness of the assumptions, including whether the assumptions used were reasonable considering the past performance of the Company, and whether they were consistent with evidence obtained in other areas of the audit. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of these estimates of proved oil and natural gas reserves. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of data used by management's specialists, and an evaluation of the specialists' findings.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 26, 2020

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

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2019	2018	2017
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue		255,583	279,332	237,162
Income from equity affiliates	7	5,441	7,355	5,380
Other income		3,914	3,525	1,821
Total revenues and other income		264,938	290,212	244,363
Costs and other deductions				
Crude oil and product purchases		143,801	156,172	128,217
Production and manufacturing expenses		36,826	36,682	32,690
Selling, general and administrative expenses		11,398	11,480	10,649
Depreciation and depletion	9	18,998	18,745	19,893
Exploration expenses, including dry holes		1,269	1,466	1,790
Non-service pension and postretirement benefit expense	17	1,235	1,285	1,745
Interest expense		830	766	601
Other taxes and duties	19	30,525	32,663	30,104
Total costs and other deductions		244,882	259,259	225,689

Income before income taxes		20,056	30,953	18,674
Income taxes	19	5,282	9,532	(1,174)
Net income including noncontrolling interests		14,774	21,421	19,848
Net income attributable to noncontrolling interests		434	581	138
Net income attributable to ExxonMobil		14,340	20,840	19,710
Earnings per common share *(dollars)*	12	3.36	4.88	4.63
Earnings per common share - assuming dilution *(dollars)*	12	3.36	4.88	4.63

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2019	2018	2017
		(millions of dollars)	
Net income including noncontrolling interests	14,774	21,421	19,848
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	1,735	(5,077)	5,352
Adjustment for foreign exchange translation (gain)/loss			
included in net income	-	196	234
Postretirement benefits reserves adjustment (excluding amortization)	(2,092)	280	(219)
Amortization and settlement of postretirement benefits reserves			
adjustment included in net periodic benefit costs	582	931	1,165
Total other comprehensive income	225	(3,670)	6,532
Comprehensive income including noncontrolling interests	14,999	17,751	26,380
Comprehensive income attributable to noncontrolling interests	588	174	693
Comprehensive income attributable to ExxonMobil	14,411	17,577	25,687

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2019	Dec. 31 2018
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		3,089	3,042
Notes and accounts receivable, less estimated doubtful amounts	6	26,966	24,701
Inventories			
Crude oil, products and merchandise	3	14,010	14,803
Materials and supplies		4,518	4,155
Other current assets		1,469	1,272
Total current assets		50,052	47,973
Investments, advances and long-term receivables	8	43,164	40,790
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	253,018	247,101
Other assets, including intangibles, net		16,363	10,332
Total assets		362,597	346,196
Liabilities			
Current liabilities			
Notes and loans payable	6	20,578	17,258
Accounts payable and accrued liabilities	6	41,831	37,268
Income taxes payable		1,580	2,612
Total current liabilities		63,989	57,138
Long-term debt	14	26,342	20,538
Postretirement benefits reserves	17	22,304	20,272

Deferred income tax liabilities	19	25,620	27,244
Long-term obligations to equity companies		3,988	4,382
Other long-term obligations		21,416	18,094
Total liabilities		163,659	147,668
Commitments and contingencies	16		
Equity			
Common stock without par value			
(9,000 million shares authorized, 8,019 million shares issued)		15,637	15,258
Earnings reinvested		421,341	421,653
Accumulated other comprehensive income		(19,493)	(19,564)
Common stock held in treasury			
(3,785 million shares in 2019 and 3,782 million shares in 2018)		(225,835)	(225,553)
ExxonMobil share of equity		191,650	191,794
Noncontrolling interests		7,288	6,734
Total equity		198,938	198,528
Total liabilities and equity		362,597	346,196

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2019	2018	2017
			(millions of dollars)	
Cash flows from operating activities				
Net income including noncontrolling interests		14,774	21,421	19,848
Adjustments for noncash transactions				
Depreciation and depletion	9	18,998	18,745	19,893
Deferred income tax charges/(credits)		(944)	(60)	(8,577)
Postretirement benefits expense				
in excess of/(less than) net payments		109	1,070	1,135
Other long-term obligation provisions				
in excess of/(less than) payments		(3,038)	(68)	(610)
Dividends received greater than/(less than) equity in current				
earnings of equity companies		(936)	(1,684)	131
Changes in operational working capital, excluding cash and debt				
Reduction/ (increase) - Notes and accounts receivable		(2,640)	(545)	(3,954)
- Inventories		72	(3,107)	(1,682)
- Other current assets		(234)	(25)	(117)
Increase/ (reduction) - Accounts and other payables		3,725	2,321	5,104
Net (gain) on asset sales	5	(1,710)	(1,993)	(334)
All other items - net		1,540	(61)	(771)
Net cash provided by operating activities		29,716	36,014	30,066
Cash flows from investing activities				
Additions to property, plant and equipment		(24,361)	(19,574)	(15,402)

Proceeds associated with sales of subsidiaries, property, plant				
and equipment, and sales and returns of investments		3,692	4,123	3,103
Additional investments and advances		(3,905)	(1,981)	(5,507)
Other investing activities including collection of advances		1,490	986	2,076
Net cash used in investing activities		(23,084)	(16,446)	(15,730)
Cash flows from financing activities				
Additions to long-term debt		7,052	46	60
Reductions in long-term debt		(1)	-	-
Additions to short-term debt		-	-	1,735
Reductions in short-term debt		(4,043)	(4,752)	(5,024)
Additions/(reductions) in commercial paper, and debt with				
three months or less maturity	5	5,654	(219)	2,181
Cash dividends to ExxonMobil shareholders		(14,652)	(13,798)	(13,001)
Cash dividends to noncontrolling interests		(192)	(243)	(184)
Changes in noncontrolling interests		158	146	(150)
Common stock acquired		(594)	(626)	(747)
Net cash used in financing activities		(6,618)	(19,446)	(15,130)
Effects of exchange rate changes on cash		33	(257)	314
Increase/(decrease) in cash and cash equivalents		47	(135)	(480)
Cash and cash equivalents at beginning of year		3,042	3,177	3,657
Cash and cash equivalents at end of year		3,089	3,042	3,177

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	Total Equity
				(millions of dollars)			
Balance as of December 31, 2016	12,157	407,831	(22,239)	(230,424)	167,325	6,505	173,830
Amortization of stock-based awards	801	-	-	-	801	-	801
Other	(380)	-	-	-	(380)	(52)	(432)
Net income for the year	-	19,710	-	-	19,710	138	19,848
Dividends - common shares	-	(13,001)	-	-	(13,001)	(184)	(13,185)
Other comprehensive income	-	-	5,977	-	5,977	555	6,532
Acquisitions, at cost	-	-	-	(828)	(828)	(150)	(978)
Issued for acquisitions	2,078	-	-	5,711	7,789	-	7,789
Dispositions	-	-	-	295	295	-	295
Balance as of December 31, 2017	14,656	414,540	(16,262)	(225,246)	187,688	6,812	194,500
Amortization of stock-based awards	758	-	-	-	758	-	758
Other	(156)	-	-	-	(156)	436	280
Net income for the year	-	20,840	-	-	20,840	581	21,421
Dividends - common shares	-	(13,798)	-	-	(13,798)	(243)	(14,041)
Cumulative effect of accounting change	-	71	(39)	-	32	15	47
Other comprehensive income	-	-	(3,263)	-	(3,263)	(407)	(3,670)
Acquisitions, at cost	-	-	-	(626)	(626)	(460)	(1,086)
Dispositions	-	-	-	319	319	-	319
Balance as of December 31, 2018	15,258	421,653	(19,564)	(225,553)	191,794	6,734	198,528

Amortization of stock-based awards	697	-	-	-	697	-	697
Other	(318)	-	-	-	(318)	489	171
Net income for the year	-	14,340	-	-	14,340	434	14,774
Dividends - common shares	-	(14,652)	-	-	(14,652)	(192)	(14,844)
Other comprehensive income	-	-	71	-	71	154	225
Acquisitions, at cost	-	-	-	(594)	(594)	(331)	(925)
Dispositions	-	-	-	312	312	-	312
Balance as of December 31, 2019	15,637	421,341	(19,493)	(225,835)	191,650	7,288	198,938

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2016	8,019	(3,871)	4,148
Acquisitions	-	(10)	(10)
Issued for acquisitions	-	96	96
Dispositions	-	5	5
Balance as of December 31, 2017	8,019	(3,780)	4,239
Acquisitions	-	(8)	(8)
Dispositions	-	6	6
Balance as of December 31, 2018	8,019	(3,782)	4,237
Acquisitions	-	(8)	(8)
Dispositions	-	5	5
Balance as of December 31, 2019	8,019	(3,785)	4,234

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

The Corporation's principal business 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.

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years' data has been reclassified in certain cases to conform to the 2019 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation and Accounting for Investments

The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses. Amounts representing the Corporation's interest in entities that it does not control, but over which it exercises significant influence, are included in "Investments, advances and long-term receivables". The Corporation's share of the net income of these companies is included in the Consolidated Statement of Income caption "Income from equity affiliates".

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

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

Investments in equity securities other than consolidated subsidiaries and equity method investments are measured at fair value with changes in fair value recognized in net income. The Corporation uses the modified approach for equity securities that do not have a readily determinable fair value. This modified approach measures investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions in a similar investment of the same issuer.

The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in "Accumulated other comprehensive income".

Revenue Recognition

The Corporation generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments to reflect market conditions. Revenue is recognized at the amount the Corporation expects to receive when the customer has taken control, which is typically when title transfers and the customer has assumed the risks and rewards of ownership. The prices of certain sales are based on price indices that are sometimes not available until the next period. In such cases, estimated realizations are accrued when the sale is recognized, and are finalized when the price is available. Such adjustments to revenue from performance obligations satisfied in previous periods are not significant. Payment for revenue transactions is typically due within 30 days. Future volume delivery obligations that are unsatisfied at the end of the period are expected to be fulfilled through ordinary production or purchases. These performance obligations are based on market prices at the time of the transaction and are fully constrained due to market price volatility.

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

"Sales and other operating revenue" and "Notes and accounts receivable" primarily arise from contracts with customers. Long-term receivables are primarily from non-customers. Contract assets are mainly from marketing assistance programs and are not significant. Contract liabilities are mainly customer prepayments and accruals of expected volume discounts and are not significant.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Income and Other Taxes

The Corporation excludes from the Consolidated Statement of Income certain sales and value-added taxes imposed on and concurrent with revenue-producing transactions with customers and collected on behalf of governmental authorities. Similar taxes, for which the Corporation is not considered to be an agent for the government, are reported on a gross basis (included in both "Sales and other operating revenue" and "Other taxes and duties").

The Corporation accounts for U.S. tax on global intangible low-taxed income as an income tax expense in the period in which it is incurred.

Derivative Instruments

The Corporation may use derivative instruments for trading purposes and to offset exposures associated with commodity prices, foreign currency exchange rates and interest rates that arise from existing assets, liabilities, firm commitments and forecasted transactions. All derivative instruments, except those designated as normal purchase and normal sale, are recorded at fair value. Derivative assets and liabilities with the same counterparty are netted if the right of offset exists and certain other criteria are met. Collateral payables or receivables are netted against derivative assets and derivative liabilities, respectively.

Recognition and classification of the gain or loss that results from adjusting a derivative to fair value depends on the purpose for the derivative. All gains and losses from derivative instruments for which the Corporation does not apply hedge accounting are immediately recognized in earnings. We may designate derivatives as fair value or cash flow hedges. For fair value hedges, the gain or loss from derivative instruments and the offsetting gain or loss from the hedged item are recognized in earnings. For cash flow hedges, the gain or loss from the derivative instrument is initially reported as a component of other comprehensive income and subsequently reclassified into earnings in the period that the forecasted transaction affects earnings.

Fair Value

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

Inventories

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

Property, Plant and Equipment

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

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

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

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.

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

Impairment Assessment. The Corporation tests assets or groups of assets for recoverability 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 analysis, profitability reviews and other periodic control processes 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 development 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.

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.

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. 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 including price differentials, refining and chemical margins, volumes, development and operating costs, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. 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.

Other. Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any substantial obligation for future performance by the Corporation. Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

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

Asset Retirement Obligations and Environmental Liabilities

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

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

Foreign Currency Translation

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

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

Upstream operations, primarily in Asia and Africa, use the U.S. dollar because they predominantly sell crude and natural gas production into U.S. dollar-denominated markets.

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

2. Accounting Changes

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. 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, 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, which were not previously accounted for as leases, are or contain a lease. At adoption on January 1, 2019, an operating lease liability of $3.3 billion was recorded and the operating lease right of use asset was $4.3 billion, including $1.0 billion of previously recorded prepaid leases. There was no cumulative earnings effect adjustment.

Effective January 1, 2020, the Corporation adopted the Financial Accounting Standards Board's update, *Financial Instruments – Credit Losses (Topic 326)*, as amended. The standard requires a valuation allowance for credit losses be recognized for certain financial assets that reflects the current expected credit loss over the asset's contractual life. The valuation allowance considers the risk of loss, even if remote, and considers past events, current conditions and expectations of the future. The standard is not expected to have a material impact on the Corporation's financial statements.

3. Miscellaneous Financial Information

Research and development expenses totaled $1,214 million in 2019, $1,116 million in 2018, and $1,063 million in 2017.

Net income included before-tax aggregate foreign exchange transaction losses of $104 million and $138 million in 2019 and 2018, respectively, and a gain of $6 million in 2017.

In 2019, 2018, and 2017, net income included gains of $523 million and $107 million, and a loss of $10 million, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $9.7 billion and $8.2 billion at December 31, 2019, and 2018, respectively.

Crude oil, products and merchandise as of year-end 2019 and 2018 consist of the following:

	2019	**2018**
	(millions of dollars)	
Crude oil	5,111	4,783
Petroleum products	5,281	5,666
Chemical products	3,240	3,821
Gas/other	378	533
Total	14,010	14,803

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	Cumulative Foreign Exchange Translation Adjustment	Post-retirement Benefits Reserves Adjustment	Total
	(millions of dollars)		
Balance as of December 31, 2016	(14,501)	(7,738)	(22,239)
Current period change excluding amounts reclassified from accumulated other comprehensive income	4,879	(170)	4,709
Amounts reclassified from accumulated other comprehensive income	140	1,128	1,268
Total change in accumulated other comprehensive income	5,019	958	5,977
Balance as of December 31, 2017	(9,482)	(6,780)	(16,262)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(4,595)	201	(4,394)
Amounts reclassified from accumulated other comprehensive income	196	896	1,092
Total change in accumulated other comprehensive income	(4,399)	1,097	(3,302)
Balance as of December 31, 2018	(13,881)	(5,683)	(19,564)
Current period change excluding amounts reclassified from accumulated other comprehensive income	1,435	(1,927)	(492)
Amounts reclassified from accumulated other comprehensive income	-	563	563

Total change in accumulated other comprehensive income	1,435	(1,364)	71
Balance as of December 31, 2019	(12,446)	(7,047)	(19,493)

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)	**2019**	**2018**	**2017**
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	-	(196)	(234)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs (Statement of Income line: Non-service pension and postretirement benefit expense)	(751)	(1,208)	(1,656)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	**2019**	**2018**	**2017**
		(millions of dollars)	
Foreign exchange translation adjustment	88	32	67
Postretirement benefits reserves adjustment (excluding amortization)	719	(193)	201
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(169)	(277)	(491)
Total	638	(438)	(223)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Cash Flow Information

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

For 2019, the "Net (gain) on asset sales" on the Consolidated Statement of Cash Flows includes before-tax amounts from the sale of non-operated upstream assets in Norway and upstream asset transactions in the U.S. For 2018, the number includes before-tax amounts from the sale of service stations in Germany, the divestment of the Augusta refinery in Italy, and the sale of an undeveloped upstream property in Australia. For 2017, the number includes before-tax amounts from the sale of service stations in multiple countries, upstream asset transactions in the U.S., and the sale of ExxonMobil's operated upstream business in Norway. These net gains are reported in "Other income" on the Consolidated Statement of Income.

In 2019, the "Additions/(reductions) in commercial paper, and debt with three months or less maturity" on the Consolidated Statement of Cash Flows includes a net $4.6 billion addition of commercial paper with maturity over three months. The gross amount issued was $18.9 billion, while the gross amount repaid was $14.3 billion. In 2018, the number includes a net $275 million addition of commercial paper with maturity over three months. The gross amount issued was $4.0 billion, while the gross amount repaid was $3.8 billion. In 2017, the number includes a net $121 million repayment of commercial paper with maturity over three months. The gross amount issued was $3.6 billion, while the gross amount repaid was $3.7 billion.

In 2017, the Corporation completed the acquisitions of InterOil Corporation, mostly unproved properties in Papua New Guinea, for $2.7 billion and of companies that own mostly unproved oil and gas properties in the Permian Basin and other assets for $6.2 billion. These transactions included a significant noncash component associated with the issuance of a total of 96 million shares of Exxon Mobil Corporation common stock in acquisition consideration, having a total acquisition date value of $7.8 billion.

	2019	2018	2017
		(millions of dollars)	
Income taxes paid	7,018	9,294	7,510
Cash interest paid			
Included in cash flows from operating activities	560	303	383
Capitalized, included in cash flows from investing activities	731	652	749
Total cash interest paid	1,291	955	1,132

6. Additional Working Capital Information

	Dec. 31 2019	Dec. 31 2018
	(millions of dollars)	
Notes and accounts receivable		

Trade, less reserves of $34 million and $61 million	21,100	19,638
Other, less reserves of $371 million and $339 million	5,866	5,063
Total	26,966	24,701

Notes and loans payable		
Bank loans	316	325
Commercial paper	18,561	12,863
Long-term debt due within one year	1,701	4,070
Total	20,578	17,258

Accounts payable and accrued liabilities		
Trade payables	24,694	21,063
Payables to equity companies	6,825	6,863
Accrued taxes other than income taxes	3,301	3,280
Other	7,011	6,062
Total	41,831	37,268

The Corporation has short-term committed lines of credit of $7.9 billion which were unused as of December 31, 2019. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 1.7 percent and 2.4 percent at December 31, 2019, and 2018, respectively.

7. Equity Company Information

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

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 13 percent, 14 percent and 15 percent in the years 2019, 2018 and 2017, respectively.

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

	2019		2018		2017	
Equity Company		**ExxonMobil**		**ExxonMobil**		**ExxonMobil**
Financial Summary	**Total**	**Share**	**Total**	**Share**	**Total**	**Share**
			(millions of dollars)			
Total revenues	102,365	31,240	112,938	34,539	94,791	29,340
Income before income taxes	29,424	7,927	37,203	10,482	29,748	8,498
Income taxes	9,725	2,500	11,568	3,151	8,421	2,236
Income from equity affiliates	19,699	5,427	25,635	7,331	21,327	6,262
Current assets	36,035	12,661	38,670	13,394	35,367	12,050
Long-term assets	143,321	40,001	128,830	35,970	122,221	34,931
Total assets	179,356	52,662	167,500	49,364	157,588	46,981
Current liabilities	24,583	6,939	27,324	7,606	21,725	6,348
Long-term liabilities	61,022	18,158	56,913	17,109	59,736	17,056
Net assets	93,751	27,565	83,263	24,649	76,127	23,577

A list of significant equity companies as of December 31, 2019, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	
Aera Energy LLC	48
Barzan Gas Company Limited	7
BEB Erdgas und Erdoel GmbH & Co. KG	50
Cameroon Oil Transportation Company S.A.	41
Caspian Pipeline Consortium - Kazakhstan	8
Coral FLNG, S.A.	25
Cross Timbers Energy, LLC	50
Golden Pass Pipeline LLC	30
Golden Pass LNG Terminal LLC	30
Marine Well Containment Company LLC	10
Mozambique Rovuma Venture, S.p.A.	36
Nederlandse Aardolie Maatschappij B.V.	50
Papua New Guinea Liquefied Natural Gas Global Company LDC	33
Permian Highway Pipeline LLC	20
Qatar Liquefied Gas Company Limited	10
Qatar Liquefied Gas Company Limited (2)	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited (II)	31
Ras Laffan Liquefied Natural Gas Company Limited (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	71

Downstream

Alberta Products Pipe Line Ltd.	45
Fujian Refining & Petrochemical Co. Ltd.	25
Permian Express Partners LLC	12
Saudi Aramco Mobil Refinery Company Ltd.	50

Chemical

Al-Jubail Petrochemical Company	50
Gulf Coast Growth Ventures LLC	50
Infineum Italia s.r.l.	50
Infineum Singapore LLP	50
Saudi Yanbu Petrochemical Co.	50

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2019	Dec. 31, 2018
	(millions of dollars)	
Equity method company investments and advances		
Investments	29,291	26,382
Advances	8,542	8,608
Total equity method company investments and advances	37,833	34,990
Equity securities carried at fair value and other investments at adjusted cost basis	190	210
Long-term receivables and miscellaneous, net of reserves of $5,643 million and $5,471 million	5,141	5,590
Total	43,164	40,790

9. Property, Plant and Equipment and Asset Retirement Obligations

	December 31, 2019		December 31, 2018	
Property, Plant and Equipment	Cost	Net	Cost	Net
	(millions of dollars)			
Upstream	376,041	196,767	372,791	194,662
Downstream	52,527	24,506	48,241	21,448
Chemical	40,788	21,260	39,008	20,551
Other	17,346	10,485	17,150	10,440
Total	486,702	253,018	477,190	247,101

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 2019, 2018 and 2017, the before-tax impairment charges were $0.1 billion, $0.7 billion and $2.0 billion, respectively.

Accumulated depreciation and depletion totaled $233,684 million at the end of 2019 and $230,089 million at the end of 2018. Interest capitalized in 2019, 2018 and 2017 was $731 million, $652 million and $749 million, respectively.

Asset Retirement Obligations

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

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

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

	2019	**2018**
	(millions of dollars)	
Beginning balance	12,103	12,705
Accretion expense and other provisions	649	681
Reduction due to property sales	(1,085)	(333)
Payments made	(827)	(600)
Liabilities incurred	89	46
Foreign currency translation	84	(481)
Revisions	267	85
Ending balance	11,280	12,103

The long-term Asset Retirement Obligations were $10,279 million and $11,185 million at December 31, 2019, and 2018, respectively, and are included in “Other long-term obligations.”

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. Accounting for Suspended Exploratory Well Costs

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

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

Change in capitalized suspended exploratory well costs:

	2019	2018	2017
		(millions of dollars)	
Balance beginning at January 1	4,160	3,700	4,477
Additions pending the determination of proved reserves	532	564	906
Charged to expense	(46)	(7)	(1,205)
Reclassifications to wells, facilities and equipment based on the			
determination of proved reserves	(37)	(48)	(497)
Divestments/Other	4	(49)	19
Ending balance at December 31	4,613	4,160	3,700
Ending balance attributed to equity companies included above	306	306	306

Period end capitalized suspended exploratory well costs:

	2019	2018	2017
		(millions of dollars)	
Capitalized for a period of one year or less	532	564	906
Capitalized for a period of between one and five years	2,206	2,028	1,345
Capitalized for a period of between five and ten years	1,411	1,150	1,064
Capitalized for a period of greater than ten years	464	418	385
Capitalized for a period greater than one year - subtotal	4,081	3,596	2,794
Total	4,613	4,160	3,700

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a breakdown of the number of projects with only exploratory well costs capitalized for a period of one year or less and those that have had exploratory well costs capitalized for a period greater than one year.

	2019	2018	2017
Number of projects that only have exploratory well costs capitalized for a period			
of one year or less	4	6	11
Number of projects that have exploratory well costs capitalized for a period			
greater than one year	46	52	46
Total	50	58	57

Of the 46 projects that have exploratory well costs capitalized for a period greater than one year as of December 31, 2019, 14 projects have drilling in the preceding year or exploratory activity planned in the next two years, while the remaining 32 projects are those with completed exploratory activity progressing toward development.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The table below provides additional detail for those 32 projects, which total $3,176 million.

Country/Project	Dec. 31, 2019	Years Wells Drilled / Acquired	Comment
(millions of dollars)			
Angola			
- AB32 Central NE Hub	69	2006-2014	Evaluating development plan for tieback to existing production facilities.
- Kaombo Split Hub Phase 2	20	2005-2006	Evaluating development plan to tie into planned production facilities.
Argentina			
- La Invernada	72	2014	Evaluating development plan to tie into planned infrastructure.
Australia			
- East Pilchard	7	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/ planned infrastructure.
- Gorgon Area Ullage	315	1994-2015	Evaluating development plans to tie into existing LNG facilities.
- SE Longtom	10	2010	Gas field near Tuna development, awaiting capacity in existing/ planned infrastructure.
- SE Remora	32	2010	Gas field near Marlin development, awaiting capacity in existing/ planned infrastructure.
Guyana			
- Payara	120	2017-2018	Continuing development plan discussions with the government.
Iraq			
- Kurdistan Pirmam	109	2015	Evaluating commercialization alternatives, while waiting for government approval to enter Gas Holding Period.
Kazakhstan			

- Kairan	53	2004-2007	Evaluating commercialization and field development alternatives, while continuing discussions with the government regarding the development plan.
Mozambique			
- Rovuma LNG Future Non-Straddling Train	120	2017	Evaluating/progressing development plan to tie into planned LNG facilities.
- Rovuma LNG Phase 1	150	2017	Progressing development plan to tie into planned LNG facilities.
- Rovuma LNG Unitized Trains	35	2017	Evaluating/progressing development plan to tie into planned LNG facilities.
Nigeria			
- Bolia	15	2002-2006	Evaluating development plan, while continuing discussions with the government regarding regional hub strategy.
- Bonga North	34	2004-2009	Evaluating/progressing development plan for tieback to existing/ planned infrastructure.
- Bosi	79	2002-2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Bosi Central	16	2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Erha Northeast	26	2008	Evaluating development plan for tieback to existing production facilities.
- OML 138 Ukot SS	13	2015	Evaluating development plan for tieback to existing production facilities.
- OML 138 Ukot SW	41	2014	Evaluating development plan for tieback to existing production facilities.
- Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
- Satellite Field Development Phase 2	12	2013	Evaluating development plan to tie into planned production facilities.

- Other (4 projects)	10	2001-2002	Evaluating and pursuing development of several additional discoveries.

Country/Project	Dec. 31, 2019	Years Wells Drilled / Acquired	Comment
(millions of dollars)			
Papua New Guinea			
- Papua LNG	246	2017	Evaluating/progressing development plans.
- P'nyang	115	2012-2018	Evaluating/progressing development plans.
Republic of Congo			
- Mer Tres Profonde Sud	56	2000-2007	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
Romania			
- Neptun Deep	536	2012-2016	Continuing discussions with the government regarding development plan.
Tanzania			
- Tanzania Block 2	537	2012-2018	Evaluating development alternatives while continuing discussions with the government regarding development plan.
Vietnam			
- Blue Whale	296	2011-2015	Evaluating/progressing development plans.
Total 2019 (32 projects)	3,176		

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. Leases

The Corporation and its consolidated affiliates generally purchase the property, plant and equipment used in operations, but there are situations where assets are leased, primarily for drilling equipment, tankers, office buildings, railcars, and other moveable equipment. Right of use assets and lease liabilities are established on the balance sheet for leases with an expected term greater than one year, by discounting the amounts fixed in the lease agreement for the duration of the lease which is reasonably certain, considering the probability of exercising any early termination and extension options. The portion of the fixed payment related to service costs for drilling equipment, tankers and finance leases is excluded from the calculation of right of use assets and lease liabilities. Generally assets are leased only for a portion of their useful lives, and are accounted for as operating leases. In limited situations assets are leased for nearly all of their useful lives, and are accounted for as finance leases.

Variable payments under these lease agreements are not significant. Residual value guarantees, restrictions, or covenants related to leases, and transactions with related parties are also not significant. In general, leases are capitalized using the incremental borrowing rate of the leasing affiliate. The Corporation's activities as a lessor are not significant.

At adoption of the lease accounting change (see Note 2), on January 1, 2019, an operating lease liability of $3.3 billion was recorded and the operating lease right of use asset was $4.3 billion, including $1.0 billion of previously recorded prepaid leases. There was no cumulative earnings effect adjustment.

	Operating Leases			
	Drilling Rigs and Related Equipment	Other	Total	Finance Leases
	(millions of dollars)			
Lease Cost	2019			
Operating lease cost	238	1,196	1,434	
Short-term and other (net of sublease rental income)	926	1,116	2,042	
Amortization of right of use assets				121
Interest on lease liabilities				133
Total	1,164	2,312	3,476	254

Operating Leases

	Drilling Rigs and Related Equipment	Other	Total	Finance Leases
	(millions of dollars)			
Balance Sheet	December 31, 2019			
Right of use assets				
Included in Other assets, including intangibles - net	572	6,061	6,633	
Included in Property, plant and equipment - net				1,997
Total right of use assets	572	6,061	6,633	1,997
Lease liability due within one year				
Included in Accounts payable and accrued liabilities	221	990	1,211	15
Included in Notes and loans payable				84
Long-term lease liability				
Included in Other long-term obligations	330	4,152	4,482	
Included in Long-term debt				1,670
Included in Long-term obligations to equity companies				139
Total lease liability	551	5,142	5,693	1,908

	Operating Leases			
	Drilling Rigs and Related Equipment	Other	Total	Finance Leases
	(millions of dollars)			
Maturity Analysis of Lease Liabilities	**December 31, 2019**			
2020	234	1,127	1,361	271
2021	134	886	1,020	576
2022	73	625	698	174
2023	45	468	513	173
2024	30	425	455	172
2025 and beyond	72	2,681	2,753	2,446
Total lease payments	588	6,212	6,800	3,812
Discount to present value	(37)	(1,070)	(1,107)	(1,904)
Total lease liability	551	5,142	5,693	1,908
Weighted average remaining lease term - years	4	11	10	20
Weighted average discount rate - percent	3.1%	3.2%	3.2%	9.7%

In addition to the lease liabilities in the table immediately above, at December 31, 2019, undiscounted commitments for leases not yet commenced totaled $848 million for operating leases and $3,721 million for finance leases. The finance leases relate to floating production storage and offloading vessels, LNG transportation vessels, and a long-term hydrogen purchase agreement. The underlying assets for these finance leases were primarily designed by, and are being constructed by, the lessors.

	Operating Leases		
	Drilling Rigs and Related		Finance

Other Information	Equipment	Other	Total	Leases
	(millions of dollars)			
	2019			
Cash paid for amounts included in the measurement of lease liabilities				
Cash flows from operating activities		1,116	1,116	54
Cash flows from investing activities	258		258	
Cash flows from financing activities				177
Noncash right of use assets recorded for lease liabilities				
For January 1 adoption of *Topic 842*	445	2,818	3,263	
In exchange for new lease liabilities during the period	350	3,313	3,663	422

Disclosures under the previous lease standard (ASC 840)

Net rental cost incurred under both cancelable and noncancelable operating leases was $2,715 million in 2018 and $2,618 million in 2017. At December 31, 2018, minimum undiscounted lease commitments under noncancelable operating leases and charters for 2019 and beyond were $6,112 million.

12. Earnings Per Share

Earnings per common share	2019	2018	2017
Net income attributable to ExxonMobil *(millions of dollars)*	14,340	20,840	19,710
Weighted average number of common shares outstanding *(millions of shares)*	4,270	4,270	4,256
Earnings per common share *(dollars) (1)*	3.36	4.88	4.63
Dividends paid per common share *(dollars)*	3.43	3.23	3.06

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

13. Financial Instruments and Derivatives

Financial Instruments. The estimated fair value of financial instruments at December 31, 2019 and December 31, 2018, and the related hierarchy level for the fair value measurement is as follows:

	At December 31, 2019							
	(millions of dollars)							
	Fair Value							
	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets *(1)*	533	102	-	635	(463)	(70)	-	102
Advances to/receivables from equity companies *(2) (7)*	-	1,941	6,729	8,670	-	-	(128)	8,542
Other long-term financial assets *(3)*	1,145	-	974	2,119	-	-	44	2,163
Liabilities								
Derivative liabilities *(4)*	568	70	-	638	(463)	(105)	-	70
Long-term debt *(5)*	25,652	134	3	25,789	-	-	(1,117)	24,672
Long-term obligations to equity companies *(7)*	-	-	4,245	4,245	-	-	(257)	3,988
Other long-term financial liabilities *(6)*	-	-	1,042	1,042	-	-	16	1,058

	At December 31, 2018							
	(millions of dollars)							
	Fair Value							
	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value
Assets								
Derivative assets *(1)*	297	-	-	297	(151)	(146)	-	-
Advances to/receivables								
from equity companies *(2) (7)*	-	2,100	6,293	8,393	-	-	215	8,608
Other long-term								
financial assets *(3)*	848	-	974	1,822	-	-	112	1,934
Liabilities								
Derivative liabilities *(4)*	151	-	-	151	(151)	-	-	-
Long-term debt *(5)*	19,029	117	4	19,150	-	-	85	19,235
Long-term obligations								
to equity companies *(7)*	-	-	4,330	4,330	-	-	52	4,382
Other long-term								
financial liabilities *(6)*	-	-	1,046	1,046	-	-	(3)	1,043

(1) Included in the Balance Sheet lines: Notes and accounts receivable, less estimated doubtful amounts and Other assets, including intangibles, net

(2) Included in the Balance Sheet line: Investments, advances and long-term receivables

(3) Included in the Balance Sheet lines: Investments, advances and long term receivables and Other assets, including intangibles, net

(4) Included in the Balance Sheet lines: Accounts payable and accrued liabilities and Other long-term obligations

(5) Excluding finance lease obligations

(6) Included in the Balance Sheet line: Other long-term obligations

(7) Advances to/receivables from equity companies and long-term obligations to equity companies are mainly designated as hierarchy level 3 inputs. The fair value is calculated by discounting the remaining obligations by a rate consistent with the credit quality and industry of the company.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The increase in the estimated fair value and book value of long-term debt reflects the Corporation's issuance of $7.0 billion of long-term debt in the third quarter of 2019.

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in 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. Commodity contracts held for trading purposes are presented in the Consolidated Statement of Income on a net basis in the line "Sales and other operating revenue". The Corporation's commodity derivatives are not accounted for under hedge accounting. At times, the Corporation also enters into currency and interest rate derivatives, none of which are material to the Corporation's financial position as of December 31, 2019 and 2018, or results of operations for the years ended 2019, 2018 and 2017.

Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

At December 31, 2019, the net notional long/(short) position of derivative instruments was 57 million barrels for crude oil, (38) million barrels for products, and (165) million MMBtus of natural gas. At December 31, 2018, the net notional long/(short) position of derivative instruments was (19) million barrels for crude oil and was (9) million barrels for products.

Realized and unrealized gains/(losses) on derivative instruments that were recognized in the Consolidated Statement of Income are included in the following lines on a before-tax basis:

	2019	2018	2017
		(millions of dollars)	
Sales and other operating revenue	(412)	130	6
Crude oil and product purchases	179	(120)	(105)
Total	(233)	10	(99)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

14. Long-Term Debt

At December 31, 2019, long-term debt consisted of $25,710 million due in U.S. dollars and $632 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $1,617 million, which matures within one year and is included in current liabilities. The increase in the book value of long-term debt reflects the Corporation's issuance of $7.0 billion of long-term debt in the third quarter of 2019. The amounts of long-term debt, excluding finance lease obligations, maturing in each of the four years after December 31, 2020, in millions of dollars, are: 2021 – $2,803; 2022 – $3,316; 2023 – $1,261; and 2024 – $2,130. At December 31, 2019, the Corporation's unused long-term credit lines were $0.2 billion.

Summarized long-term debt at year-end 2019 and 2018 are shown in the table below:

	Average Rate *(1)*	**2019**	**2018**
		(millions of dollars)	
Exxon Mobil Corporation			
1.912% notes due 2020		-	1,500
2.222% notes due 2021		2,500	2,500
2.397% notes due 2022 *(Issued 2015)*		1,150	1,150
1.902% notes due 2022 *(Issued 2019)*		750	-
Floating-rate notes due 2022 *(Issued 2015)*	2.792%	500	500
Floating-rate notes due 2022 *(Issued 2019)*	2.414%	750	-
2.726% notes due 2023		1,250	1,250
3.176% notes due 2024 *(Issued 2014)*		1,000	1,000
2.019% notes due 2024 *(Issued 2019)*		1,000	-
2.709% notes due 2025		1,750	1,750
3.043% notes due 2026 *(Issued 2016)*		2,500	2,500
2.275% notes due 2026 *(Issued 2019)*		1,000	-
2.440% notes due 2029		1,250	-
2.995% notes due 2039		750	-
3.567% notes due 2045		1,000	1,000
4.114% notes due 2046		2,500	2,500
3.095% notes due 2049		1,500	-

XTO Energy Inc. *(2)*			
6.100% senior notes due 2036		193	195
6.750% senior notes due 2037		296	299
6.375% senior notes due 2038		229	230
Mobil Corporation			
8.625% debentures due 2021		250	250
Industrial revenue bonds due 2020-2051	1.388%	2,461	2,513
Other U.S. dollar obligations		89	102
Other foreign currency obligations		64	38
Finance lease obligations	9.518%	1,670	1,303
Debt issuance costs		(60)	(42)
Total long-term debt		26,342	20,538

(1) Average effective interest rate for debt and average imputed interest rate for finance leases at December 31, 2019.

(2) Includes premiums of $92 million in 2019 and $97 million in 2018.

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock, and other forms of awards. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire, or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2019, remaining shares available for award under the 2003 Incentive Program were 76 million.

Restricted Stock and Restricted Stock Units. Awards totaling 8,936 thousand, 8,771 thousand, and 8,916 thousand of restricted (nonvested) common stock units were granted in 2019, 2018, and 2017, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

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

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2019.

	2019	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	40,381	86.56
Awards issued in 2019	8,799	77.66
Vested	(9,427)	86.94
Forfeited	(125)	85.35
Issued and outstanding at December 31	39,628	84.50

Value of restricted stock units	**2019**	**2018**	**2017**

Grant price *(dollars)*	68.77	77.66	81.89
Value at date of grant:		*(millions of dollars)*	
Units settled in stock	559	620	667
Units settled in cash	55	61	63
Total value	614	681	730

As of December 31, 2019, there was $1,754 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.4 years. The compensation cost charged against income for the restricted stock and restricted stock units was $741 million, $774 million, and $856 million for 2019, 2018, and 2017, respectively. The income tax benefit recognized in income related to this compensation expense was $51 million, $42 million, and $78 million for the same periods, respectively. The fair value of shares and units vested in 2019, 2018, and 2017 was $647 million, $722 million, and $826 million, respectively. Cash payments of $56 million, $61 million, and $64 million for vested restricted stock units settled in cash were made in 2019, 2018, and 2017, respectively.

16. Litigation and Other Contingencies

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

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2019, for guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management’s estimate of the maximum potential exposure.

	December 31, 2019		
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	827	104	931
Other	873	5,151	6,024
Total	1,700	5,255	6,955

(1) ExxonMobil share.

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

In accordance with a Venezuelan nationalization decree issued in February 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. The decree also required conversion of the Cerro Negro Project into a “mixed enterprise” and an increase in PdVSA’s or one of its affiliate’s ownership interest in the Project. ExxonMobil refused to accede to the terms proffered by the government, and on June 27, 2007, the government expropriated ExxonMobil’s 41.67 percent interest in the Cerro Negro Project.

ExxonMobil collected awards of $908 million in an arbitration against PdVSA under the rules of the International Chamber of Commerce in respect of an indemnity related to the Cerro Negro Project and $260 million in an arbitration for compensation due for the La Ceiba Project and for export curtailments at the Cerro Negro Project under rules of International Centre for Settlement of Investment Disputes (ICSID). An ICSID arbitration award relating to the Cerro Negro Project's expropriation ($1.4 billion) was annulled based on a determination that a prior Tribunal failed to adequately explain why the cap on damages in the indemnity owed by PdVSA did not affect or limit the amount owed for the expropriation of the Cerro Negro Project. ExxonMobil filed a new claim seeking to restore the original award of damages for the Cerro Negro Project with ICSID on September 26, 2018.

The net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. Regardless, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition.

An affiliate of ExxonMobil is one of the Contractors under a Production Sharing Contract (PSC) with the Nigerian National Petroleum Corporation (NNPC) covering the Erha block located in the offshore waters of Nigeria. ExxonMobil's affiliate is the operator of the block and owns a 56.25 percent interest under the PSC. The Contractors are in dispute with NNPC regarding NNPC's lifting of crude oil in excess of its entitlement under the terms of the PSC. In accordance with the terms of the PSC, the Contractors initiated arbitration in Abuja, Nigeria, under the Nigerian Arbitration and Conciliation Act. On October 24, 2011, a three-member arbitral Tribunal issued an award upholding the Contractors' position in all material respects and awarding damages to the Contractors jointly in an amount of approximately $1.8 billion plus $234 million in accrued interest. The Contractors petitioned a Nigerian federal court for enforcement of the award, and NNPC petitioned the same court to have the award set aside. On May 22, 2012, the court set aside the award. The Contractors appealed that judgment to the Court of Appeal, Abuja Judicial Division. On July 22, 2016, the Court of Appeal upheld the decision of the lower court setting aside the award. On October 21, 2016, the Contractors appealed the decision to the Supreme Court of Nigeria. In June 2013, the Contractors filed a lawsuit against NNPC in the Nigerian federal high court in order to preserve their ability to seek enforcement of the PSC in the courts if necessary. Following dismissal by this court, the Contractors appealed to the Nigerian Court of Appeal in June 2016. In October 2014, the Contractors filed suit in the United States District Court for the Southern District of New York (SDNY) to enforce, if necessary, the arbitration award against NNPC assets residing within that jurisdiction. NNPC moved to dismiss the lawsuit. On September 4, 2019, the SDNY dismissed the Contractors’ petition to recognize and enforce the Erha arbitration award. The Contractors filed a notice of appeal in the Second Circuit on October 2, 2019. At this time, the net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. However, regardless of the outcome of enforcement proceedings, the Corporation does not expect the proceedings to have a material effect upon the Corporation's operations or financial condition.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2019	2018	2019	2018	2019	2018
			(percent)			
Weighted-average assumptions used to determine						
benefit obligations at December 31						
Discount rate	3.50	4.40	2.30	3.00	3.50	4.40
Long-term rate of compensation increase	5.75	5.75	4.80	4.30	5.75	5.75
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	18,174	19,310	25,378	27,963	7,471	8,100
Service cost	757	819	551	608	139	152
Interest cost	766	721	763	754	315	301
Actuarial loss/(gain)	2,562	(957)	3,703	(1,034)	556	(630)
Benefits paid *(1) (2)*	(1,300)	(1,715)	(1,196)	(1,284)	(517)	(528)
Foreign exchange rate changes	-	-	391	(1,664)	25	(49)
Amendments, divestments and other	-	(4)	328	35	124	125
Benefit obligation at December 31	20,959	18,174	29,918	25,378	8,113	7,471
Accumulated benefit obligation at December 31	16,387	14,683	27,236	23,350	-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2019 and 2018, other postretirement benefits paid are net of $20 million and $13 million of Medicare subsidy receipts, respectively.

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the effective discount rate determined by use of a yield curve based on high-quality, noncallable bonds applied to the estimated cash outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using a spot yield curve of high-quality, local-currency-denominated bonds at an average maturity approximating that of the liabilities.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.5 percent in 2021 and subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $85 million and the postretirement benefit obligation by $921 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $63 million and the postretirement benefit obligation by $726 million.

	Pension Benefits				**Other Postretirement**	
	U.S.		**Non-U.S.**		**Benefits**	
	2019	**2018**	**2019**	**2018**	**2019**	**2018**
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	11,134	12,782	19,486	21,461	386	427
Actual return on plan assets	2,521	(710)	3,210	(15)	54	(13)
Foreign exchange rate changes	-	-	513	(1,320)	-	-
Company contribution	1,022	491	602	438	41	30
Benefits paid *(1)*	(1,041)	(1,429)	(883)	(903)	(56)	(58)
Other	-	-	(12)	(175)	-	-
Fair value at December 31	13,636	11,134	22,916	19,486	425	386

(1) Benefit payments for funded plans.

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2019	2018	2019	2018
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(4,656)	(4,604)	(1,728)	439
Unfunded plans	(2,667)	(2,436)	(5,274)	(6,331)
Total	(7,323)	(7,040)	(7,002)	(5,892)

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

	Pension Benefits				Other Postretirement	
	U.S.		Non-U.S.		Benefits	
	2019	2018	2019	2018	2019	2018
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(7,323)	(7,040)	(7,002)	(5,892)	(7,688)	(7,085)
Amounts recorded in the consolidated balance						
sheet consist of:						
Other assets	-	-	1,151	1,174	-	-

Current liabilities	(242)	(243)	(267)	(314)	(351)	(362)
Postretirement benefits reserves	(7,081)	(6,797)	(7,886)	(6,752)	(7,337)	(6,723)
Total recorded	(7,323)	(7,040)	(7,002)	(5,892)	(7,688)	(7,085)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	3,971	3,831	5,662	4,713	1,339	877
Prior service cost	1	6	360	(93)	(315)	(357)
Total recorded in accumulated other comprehensive income	3,972	3,837	6,022	4,620	1,024	520

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					(percent)				
Discount rate	4.40	3.80	4.25	3.00	2.80	3.00	4.40	3.80	4.25
Long-term rate of return on funded assets	5.30	6.00	6.50	4.10	4.70	5.20	4.60	6.00	6.50
Long-term rate of compensation increase	5.75	5.75	5.75	4.30	4.30	4.00	5.75	5.75	5.75
Components of net periodic benefit cost					(millions of dollars)				
Service cost	757	819	784	551	608	596	139	152	129
Interest cost	766	721	798	763	754	772	315	301	317
Expected return on plan assets	(568)	(727)	(775)	(777)	(951)	(1,000)	(15)	(23)	(24)
Amortization of actuarial loss/(gain)	305	362	438	306	409	476	55	116	96
Amortization of prior service cost	5	5	5	56	46	47	(42)	(40)	(33)
Net pension enhancement and curtailment/settlement cost	164	268	609	(98)	44	19	-	-	-
Net periodic benefit cost	1,429	1,448	1,859	801	910	910	452	506	485

Changes in amounts recorded in accumulated									
other comprehensive income:									
Net actuarial loss/(gain)	609	479	(324)	1,268	(66)	(191)	517	(594)	215
Amortization of actuarial (loss)/gain	(469)	(630)	(1,047)	(208)	(453)	(495)	(55)	(116)	(96)
Prior service cost/(credit)	-	-	-	379	98	111	-	-	-
Amortization of prior service (cost)/credit	(5)	(5)	(5)	(56)	(46)	(47)	42	40	33
Foreign exchange rate changes	-	-	-	19	(356)	559	-	(8)	8
Total recorded in other comprehensive income	135	(156)	(1,376)	1,402	(823)	(63)	504	(678)	160
Total recorded in net periodic benefit cost and									
other comprehensive income, before tax	1,564	1,292	483	2,203	87	847	956	(172)	645

Costs for defined contribution plans were $422 million, $391 million and $384 million in 2019, 2018 and 2017, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2019	2018	2017
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	(135)	156	1,376
Non-U.S. pension	(1,402)	823	63
Other postretirement benefits	(504)	678	(160)
Total (charge)/credit to other comprehensive income, before tax	(2,041)	1,657	1,279
(Charge)/credit to income tax (see Note 4)	550	(470)	(290)
(Charge)/credit to investment in equity companies	(19)	24	(43)
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	(1,510)	1,211	946
Charge/(credit) to equity of noncontrolling interests	146	(114)	12
(Charge)/credit to other comprehensive income attributable to ExxonMobil	(1,364)	1,097	958

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

Studies are periodically conducted to establish the preferred target asset allocation percentages. The target asset allocation for the U.S. benefit plans and the major non-U.S. plans is 30 percent equity securities and 70 percent debt securities. The equity targets for the U.S. and certain non-U.S. plans include a small allocation to private equity partnerships that primarily focus on early-stage venture capital of 4 percent and 3 percent, respectively.

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

The 2019 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2019, Using:					Fair Value Measurement at December 31, 2019, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
					(millions of dollars)					
Asset category:										
Equity securities										
U.S.	-	-	-	1,960	1,960	-	-	-	3,436	3,436
Non-U.S.	-	-	-	1,656	1,656	70 *(2)*	-	-	3,015	3,085
Private equity	-	-	-	499	499	-	-	-	489	489
Debt securities										
Corporate	-	4,932 *(3)*	-	1	4,933	-	129 *(3)*	-	4,486	4,615
Government	-	4,470 *(3)*	-	2	4,472	280 *(4)*	139 *(3)*	-	10,511	10,930
Asset-backed	-	-	-	1	1	-	21 *(3)*	-	212	233
Cash	-	-	-	107	107	33	12 *(5)*	-	61	106
Total at fair value	-	9,402	-	4,226	13,628	383	301	-	22,210	22,894
Insurance contracts at contract value					8					22
Total plan assets					13,636					22,916

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

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2019, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
	(millions of dollars)				
Asset category:					
Equity securities					
U.S.	-	-	-	81	81
Non-U.S.	-	-	-	49	49
Debt securities					
Corporate	-	92 *(2)*	-	-	92
Government	-	200 *(2)*	-	-	200
Asset-backed	-	-	-	-	-
Cash	-	-	-	3	3
Total at fair value	-	292	-	133	425

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2018 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2018, Using:					Fair Value Measurement at December 31, 2018, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
	(millions of dollars)									
Asset category:										
Equity securities										
U.S.	-	-	-	1,397	1,397	-	-	-	2,648	2,648
Non-U.S.	-	-	-	1,218	1,218	57 *(2)*	-	-	2,436	2,493
Private equity	-	-	-	516	516	-	-	-	513	513
Debt securities										
Corporate	-	4,795 *(3)*	-	1	4,796	-	102 *(3)*	-	3,713	3,815
Government	-	3,085 *(3)*	-	2	3,087	243 *(4)*	97 *(3)*	-	9,326	9,666
Asset-backed	-	-	-	1	1	-	28 *(3)*	-	218	246
Cash	-	-	-	111	111	27	3 *(5)*	-	54	84
Total at fair value	-	7,880	-	3,246	11,126	327	230	-	18,908	19,465
Insurance contracts										
at contract value					8					21
Total plan assets					11,134					19,486

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

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2018, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
			(millions of dollars)		
Asset category:					
Equity securities					
U.S.	-	-	-	64	64
Non-U.S.	-	-	-	41	41
Debt securities					
Corporate	-	88 *(2)*	-	-	88
Government	-	189 *(2)*	-	-	189
Asset-backed	-	-	-	-	-
Cash	-	-	-	4	4
Total at fair value	-	277	-	109	386

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

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

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2019	2018	2019	2018
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation				
in excess of plan assets:				
Projected benefit obligation	18,292	15,738	3,616	4,037
Accumulated benefit obligation	14,940	13,208	3,026	3,671
Fair value of plan assets	13,636	11,134	1,381	3,499
For unfunded pension plans:				
Projected benefit obligation	2,667	2,436	5,274	6,331
Accumulated benefit obligation	1,447	1,475	4,629	5,670

	Pension Benefits		Other Postretirement
	U.S.	Non-U.S.	Benefits
	(millions of dollars)		
Estimated 2020 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	527	422	89
Prior service cost *(2)*	5	70	(42)

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

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

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2020	1,030	515	-	-
Benefit payments expected in:				
2020	1,440	1,171	444	20
2021	1,339	1,162	445	21
2022	1,330	1,177	443	22
2023	1,328	1,199	440	23
2024	1,327	1,221	438	24
2025 - 2029	6,512	6,125	2,196	132

18. Disclosures about Segments and Related Information

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

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

Earnings after income tax include transfers at estimated market prices.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In the Corporate and financing segment, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense of $105 million in 2019, $84 million in 2018 and $136 million in 2017.

	Upstream		Downstream		Chemical		Corporate and	Corporate
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	Financing	Total
				(millions of dollars)				
As of December 31, 2019								
Earnings after income tax	536	13,906	1,717	606	206	386	(3,017)	14,340
Earnings of equity companies included above	282	4,534	196	19	(4)	818	(404)	5,441
Sales and other operating revenue	9,364	13,779	70,523	134,460	9,723	17,693	41	255,583
Intersegment revenue	10,893	30,864	22,416	24,775	7,864	5,905	224	-
Depreciation and depletion expense	6,162	9,305	674	832	555	621	849	18,998
Interest revenue	-	-	-	-	-	-	84	84
Interest expense	54	34	1	9	-	1	731	830
Income tax expense (benefit)	(151)	5,509	465	361	58	305	(1,265)	5,282
Additions to property, plant and equipment	10,404	7,347	2,685	1,777	1,344	589	758	24,904
Investments in equity companies	5,313	17,736	319	1,062	1,835	3,335	(309)	29,291
Total assets	95,750	151,181	23,442	37,133	16,544	20,376	18,171	362,597
As of December 31, 2018								
Earnings after income tax	1,739	12,340	2,962	3,048	1,642	1,709	(2,600)	20,840
Earnings of equity companies included above	608	5,816	156	(6)	48	1,113	(380)	7,355
Sales and other operating revenue	10,359	15,158	74,327	147,007	12,239	20,204	38	279,332
Intersegment revenue	8,683	29,659	21,954	29,888	9,044	7,217	205	-
Depreciation and depletion expense	6,024	9,257	684	890	405	606	879	18,745
Interest revenue	-	-	-	-	-	-	64	64

Interest expense	77	31	2	12	-	1	643	766
Income tax expense (benefit)	104	8,149	946	1,008	566	245	(1,486)	9,532
Additions to property, plant and equipment	7,119	7,974	1,152	1,595	1,146	348	717	20,051
Investments in equity companies	4,566	16,337	293	1,162	870	3,431	(277)	26,382
Total assets	90,310	148,914	17,898	34,024	14,904	21,131	19,015	346,196

As of December 31, 2017								
Earnings after income tax	6,622	6,733	1,948	3,649	2,190	2,328	(3,760)	19,710
Earnings of equity companies included above	216	3,618	118	490	90	1,217	(369)	5,380
Sales and other operating revenue	9,349	14,508	61,695	122,881	11,035	17,659	35	237,162
Intersegment revenue	5,729	22,935	14,857	22,263	7,270	5,550	208	-
Depreciation and depletion expense	6,963	9,741	658	883	299	504	845	19,893
Interest revenue	-	-	-	-	-	-	36	36
Interest expense	87	29	1	6	-	-	478	601
Income tax expense (benefit)	(8,552)	5,463	(61)	934	362	664	16	(1,174)
Effect of U.S. tax reform - noncash	*(7,602)*	*480*	*(618)*	-	*(335)*	-	*2,133*	*(5,942)*
Additions to property, plant and equipment	9,761	8,617	769	1,551	1,330	2,019	854	24,901
Investments in equity companies	4,680	14,494	276	1,462	341	3,387	(286)	24,354
Total assets	89,048	155,822	18,172	34,294	13,363	21,133	16,859	348,691

Geographic

Sales and other operating revenue	**2019**	**2018**	**2017**
		(millions of dollars)	
United States	89,612	96,930	82,079
Non-U.S.	165,971	182,402	155,083
Total	255,583	279,332	237,162
Significant non-U.S. revenue sources include: *(1)*			
Canada	19,735	22,672	20,116
United Kingdom	17,479	18,702	16,611
France	12,740	13,637	11,235
Singapore	12,128	13,689	11,589
Belgium	11,644	15,664	13,633
Italy	10,459	13,396	11,476

(1) Revenue is determined by primary country of operations. Excludes certain sales and other operating revenues in Non-U.S. operations where attribution to a specific country is not practicable.

Long-lived assets	**2019**	**2018**	**2017**
		(millions of dollars)	
United States	114,372	108,147	105,101
Non-U.S.	138,646	138,954	147,529
Total	253,018	247,101	252,630

Significant non-U.S. long-lived assets include:

Canada	39,130	37,433	41,138
Australia	13,933	14,548	16,908
Singapore	11,645	11,148	11,292
Kazakhstan	9,315	9,726	10,121
Papua New Guinea	8,057	8,269	8,463
Nigeria	7,640	8,421	9,734
Angola	5,784	7,021	7,689
United Arab Emirates	5,262	4,859	4,304
Russia	5,135	5,456	5,702

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

19. Income and Other Taxes

	2019			2018			2017		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
					(millions of dollars)				
Income tax expense									
Federal and non-U.S.									
Current	(121)	6,171	6,050	459	9,001	9,460	577	6,633	7,210
Deferred - net	(255)	(420)	(675)	518	(614)	(96)	(9,075)	754	(8,321)
U.S. tax on non-U.S. operations	89	-	89	42	-	42	17	-	17
Total federal and non-U.S.	(287)	5,751	5,464	1,019	8,387	9,406	(8,481)	7,387	(1,094)
State	(182)	-	(182)	126	-	126	(80)	-	(80)
Total income tax expense	(469)	5,751	5,282	1,145	8,387	9,532	(8,561)	7,387	(1,174)
All other taxes and duties									
Other taxes and duties	3,566	26,959	30,525	3,498	29,165	32,663	3,330	26,774	30,104
Included in production and									
manufacturing expenses	1,385	811	2,196	1,245	857	2,102	1,107	747	1,854
Included in SG&A expenses	160	305	465	153	312	465	147	354	501
Total other taxes and duties	5,111	28,075	33,186	4,896	30,334	35,230	4,584	27,875	32,459
Total	4,642	33,826	38,468	6,041	38,721	44,762	(3,977)	35,262	31,285

The above provisions for deferred income taxes include net credits of $740 million in 2019 and $289 million in 2018 related to changes in tax laws and rates. For 2017, deferred income tax expense includes a net credit of $5,920 million, reflecting a $5,942 million credit related to U.S. tax reform and $22 million of other changes in tax laws and rates outside of the United States.

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 tax regulations issued by the U.S. Treasury. The Corporation 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) during 2018.

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 21 percent for 2019 and 2018 and 35 percent for 2017 is as follows:

	2019	2018	2017
		(millions of dollars)	
Income before income taxes			
United States	(53)	5,200	(754)
Non-U.S.	20,109	25,753	19,428
Total	20,056	30,953	18,674
Theoretical tax	4,212	6,500	6,536
Effect of equity method of accounting	(1,143)	(1,545)	(1,883)
Non-U.S. taxes in excess of/(less than) theoretical U.S. tax *(1)*	2,573	4,626	1,848
Enactment-date effects of U.S. tax reform	-	(291)	(5,942)
Other *(2)*	(360)	242	(1,733)
Total income tax expense	5,282	9,532	(1,174)
Effective tax rate calculation			
Income taxes	5,282	9,532	(1,174)
ExxonMobil share of equity company income taxes	2,490	3,142	2,228
Total income taxes	7,772	12,674	1,054
Net income including noncontrolling interests	14,774	21,421	19,848
Total income before taxes	22,546	34,095	20,902
Effective income tax rate	34%	37%	5%

(1) 2019 includes taxes less than the theoretical U.S. tax of $773 million from Norway operations and the sale of upstream assets, $657 million from a tax rate change in Alberta, Canada, and $268 million from an adjustment to a prior year tax position.

(2) 2017 includes taxes less than the theoretical U.S. tax of $708 million from an exploration tax benefit.

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

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

Tax effects of temporary differences for:	**2019**	**2018**
	(millions of dollars)	
Property, plant and equipment	36,029	35,745
Other liabilities	7,653	6,516
Total deferred tax liabilities	43,682	42,261
Pension and other postretirement benefits	(4,712)	(4,115)
Asset retirement obligations	(3,403)	(4,118)
Tax loss carryforwards	(7,404)	(6,321)
Other assets	(7,735)	(5,498)
Total deferred tax assets	(23,254)	(20,052)
Asset valuation allowances	1,924	1,826
Net deferred tax liabilities	22,352	24,035

In 2019, asset valuation allowances of $1,924 million increased by $98 million and included net provisions of $113 million and effects of foreign currency translation of $15 million.

Balance sheet classification	**2019**	**2018**
	(millions of dollars)	
Other assets, including intangibles, net	(3,268)	(3,209)
Deferred income tax liabilities	25,620	27,244
Net deferred tax liabilities	22,352	24,035

The Corporation's undistributed earnings from subsidiary companies outside the United States include amounts that have been retained to fund prior and future capital project expenditures. Deferred income taxes have not been recorded for potential future tax obligations, such as foreign withholding tax and state tax, as these undistributed earnings are expected to be indefinitely reinvested for the foreseeable future. As of December 31, 2019, it is not practicable to estimate the unrecognized deferred tax liability. However, unrecognized deferred taxes on remittance of these funds are not expected to be material.

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

Gross unrecognized tax benefits	**2019**	**2018**	**2017**
		(millions of dollars)	
Balance at January 1	9,174	8,783	9,468
Additions based on current year's tax positions	287	375	522
Additions for prior years' tax positions	120	240	523
Reductions for prior years' tax positions	(97)	(125)	(865)
Reductions due to lapse of the statute of limitations	(279)	(5)	(113)
Settlements with tax authorities	(538)	(68)	(782)
Foreign exchange effects/other	177	(26)	30
Balance at December 31	8,844	9,174	8,783

The gross unrecognized tax benefit balances shown above are predominantly related to tax positions that would reduce the Corporation's effective tax rate if the positions are favorably resolved. Unfavorable resolution of these tax positions generally would not increase the effective tax rate. The 2019, 2018 and 2017 changes in unrecognized tax benefits did not have a material effect on the Corporation's net income.

Resolution of these tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control of the Corporation. In the United States, the Corporation has various ongoing U.S. federal income tax positions at issue with the Internal Revenue Service (IRS) for tax years beginning in 2006. The Corporation filed a refund suit for tax years 2006-2009 in U.S. federal district court with respect to the positions at issue for those years. These positions are reflected in the unrecognized tax benefits table above. On February 24, 2020, the Corporation received an adverse ruling on this suit and is assessing the ruling. Unfavorable resolution of all positions at issue with the IRS would not have a materially adverse effect on the Corporation's net income or liquidity. The IRS has asserted penalties associated with several of those positions. The Corporation has not recognized the penalties as an expense because the Corporation does not expect the penalties to be sustained under applicable law.

It is reasonably possible that the total amount of unrecognized tax benefits could increase or decrease by 10 percent in the next 12 months with no material impact on the Corporation's net income.

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

Country of Operation	**Open Tax Years**

Abu Dhabi	2013–2019
Angola	2013–2019
Australia	2010–2019
Belgium	2017–2019
Canada	2000–2019
Equatorial Guinea	2007–2019
Indonesia	2007–2019
Iraq	2014–2019
Malaysia	2011–2019
Nigeria	2006–2019
Norway	2007–2019
Papua New Guinea	2008–2019
Russia	2017–2019
United Kingdom	2015–2019
United States	2006–2019

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

The Corporation incurred $0 million, $3 million and $36 million in interest expense on income tax reserves in 2019, 2018 and 2017, respectively. The related interest payable balances were $71 million and $169 million at December 31, 2019, and 2018, respectively.

20. Sale of Norway Assets

On December 10, 2019, the Corporation completed the sale of non-operated upstream assets in Norway to Vår Energi AS (Vår). The agreed sales price of $4.5 billion was subject to interim period adjustments from the effective date of January 1, 2019, to the closing date, and reduction of obligations for income taxes from the effective date. Cash flow related to the divestment was $3.1 billion in 2019 and the Corporation expects to receive a refund of income tax payments of $0.6 billion and deferred consideration of $0.3 billion plus interest by 2022. The Corporation recognized a gain of $3.7 billion at closing of which $2.7 billion is included in “Other income” and $1.0 billion in “Income taxes” in the Consolidated Statement of Income.

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $3,502 million in 2019, $1,484 million in 2018 and $1,402 million in 2017. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2019 - Revenue							
Sales to third parties	5,070	1,452	2,141	802	2,393	3,132	14,990
Transfers	6,544	5,979	1,345	7,892	8,706	628	31,094
	11,614	7,431	3,486	8,694	11,099	3,760	46,084
Production costs excluding taxes	4,697	4,366	1,196	2,387	1,597	637	14,880
Exploration expenses	120	498	118	234	119	180	1,269
Depreciation and depletion	5,916	1,975	601	3,019	2,264	703	14,478
Taxes other than income	998	122	113	682	1,182	250	3,347
Related income tax	(29)	(423)	(20)	1,188	4,238	599	5,553
Results of producing activities for consolidated subsidiaries	(88)	893	1,478	1,184	1,699	1,391	6,557
Equity Companies							
2019 - Revenue							
Sales to third parties	664	-	1,248	-	10,536	-	12,448
Transfers	530	-	6	-	464	-	1,000
	1,194	-	1,254	-	11,000	-	13,448

Production costs excluding taxes	595	-	570	6	555	-	1,726
Exploration expenses	1	-	4	-	-	-	5
Depreciation and depletion	379	-	231	-	528	-	1,138
Taxes other than income	33	-	75	-	3,634	-	3,742
Related income tax	-	-	180	(1)	2,275	-	2,454
Results of producing activities for equity companies	186	-	194	(5)	4,008	-	4,383
Total results of operations	98	893	1,672	1,179	5,707	1,391	10,940

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2018 - Revenue							
Sales to third parties	5,914	1,491	3,680	1,136	2,431	3,256	17,908
Transfers	5,822	4,633	1,573	8,844	8,461	873	30,206
	11,736	6,124	5,253	9,980	10,892	4,129	48,114
Production costs excluding taxes	3,915	4,211	1,348	2,454	1,501	680	14,109
Exploration expenses	237	434	140	318	209	128	1,466
Depreciation and depletion	5,775	1,803	665	2,788	2,088	809	13,928
Taxes other than income	953	133	128	799	1,155	335	3,503
Related income tax	250	(121)	1,934	1,766	4,008	622	8,459
Results of producing activities for consolidated subsidiaries	606	(336)	1,038	1,855	1,931	1,555	6,649
Equity Companies							
2018 - Revenue							
Sales to third parties	747	-	1,420	-	12,028	-	14,195
Transfers	588	-	8	-	935	-	1,531
	1,335	-	1,428	-	12,963	-	15,726
Production costs excluding taxes	535	-	745	5	409	-	1,694
Exploration expenses	1	-	4	-	5	-	10
Depreciation and depletion	248	-	172	-	462	-	882
Taxes other than income	33	-	61	-	4,104	-	4,198
Related income tax	-	-	271	(1)	2,726	-	2,996

Results of producing activities for equity companies	518	-	175	(4)	5,257	-	5,946
Total results of operations	1,124	(336)	1,213	1,851	7,188	1,555	12,595
Consolidated Subsidiaries							
2017 - Revenue							
Sales to third parties	5,223	1,911	3,652	993	2,239	2,244	16,262
Transfers	3,852	3,462	1,631	7,771	6,035	689	23,440
	9,075	5,373	5,283	8,764	8,274	2,933	39,702
Production costs excluding taxes	3,730	3,833	1,576	2,064	1,618	626	13,447
Exploration expenses	162	647	94	311	494	82	1,790
Depreciation and depletion	6,689	2,005	1,055	2,957	1,782	913	15,401
Taxes other than income	684	97	146	559	811	311	2,608
Related income tax	(8,066)	(180)	1,717	1,911	2,148	316	(2,154)
Results of producing activities for consolidated subsidiaries	5,876	(1,029)	695	962	1,421	685	8,610
Equity Companies							
2017 - Revenue							
Sales to third parties	585	-	1,636	-	8,926	-	11,147
Transfers	443	-	10	-	638	-	1,091
	1,028	-	1,646	-	9,564	-	12,238
Production costs excluding taxes	523	-	418	-	336	-	1,277
Exploration expenses	1	-	13	-	878	-	892
Depreciation and depletion	320	-	166	-	477	-	963
Taxes other than income	33	-	679	-	2,997	-	3,709
Related income tax	-	-	130	-	1,924	-	2,054
Results of producing activities for equity companies	151	-	240	-	2,952	-	3,343

Total results of operations	6,027	(1,029)	935	962	4,373	685	11,953

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $13,082 million less at year-end 2019 and $13,474 million less at year-end 2018 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
Consolidated Subsidiaries								
As of December 31, 2019								
Property (acreage) costs	- Proved	19,046	2,579	49	988	2,971	719	26,352
	- Unproved	23,725	7,113	37	166	181	2,638	33,860
Total property costs		42,771	9,692	86	1,154	3,152	3,357	60,212
Producing assets		99,405	49,942	18,982	55,436	41,181	13,670	278,616
Incomplete construction		6,086	4,315	1,514	2,717	4,299	1,811	20,742
Total capitalized costs		148,262	63,949	20,582	59,307	48,632	18,838	359,570
Accumulated depreciation and depletion		63,333	21,533	17,544	43,743	22,497	7,235	175,885
Net capitalized costs for consolidated subsidiaries		84,929	42,416	3,038	15,564	26,135	11,603	183,685
Equity Companies								
As of December 31, 2019								
Property (acreage) costs	- Proved	99	-	4	308	-	-	411
	- Unproved	6	-	-	3,112	-	-	3,118

Total property costs		105	-	4	3,420	-	-	3,529
Producing assets		6,825	-	5,413	-	7,731	-	19,969
Incomplete construction		212	-	19	650	9,581	-	10,462
Total capitalized costs		7,142	-	5,436	4,070	17,312	-	33,960
Accumulated depreciation and depletion		3,288	-	4,778	-	5,380	-	13,446
Net capitalized costs for equity companies		3,854	-	658	4,070	11,932	-	20,514

Consolidated Subsidiaries

As of December 31, 2018								
Property (acreage) costs	- Proved	17,996	2,482	147	982	2,944	722	25,273
	- Unproved	26,357	6,872	45	155	179	2,692	36,300
Total property costs		44,353	9,354	192	1,137	3,123	3,414	61,573
Producing assets		95,532	45,874	28,564	53,722	39,173	13,587	276,452
Incomplete construction		4,174	2,873	1,475	3,368	4,985	1,525	18,400
Total capitalized costs		144,059	58,101	30,231	58,227	47,281	18,526	356,425
Accumulated depreciation and depletion		62,950	18,994	25,803	40,710	20,206	6,574	175,237
Net capitalized costs for consolidated subsidiaries		81,109	39,107	4,428	17,517	27,075	11,952	181,188

Equity Companies

As of December 31, 2018								
Property (acreage) costs	- Proved	98	-	4	309	-	-	411
	- Unproved	10	-	-	3,111	-	-	3,121
Total property costs		108	-	4	3,420	-	-	3,532
Producing assets		6,766	-	5,547	-	7,719	-	20,032

Incomplete construction	148	-	12	581	7,044	-	7,785
Total capitalized costs	7,022	-	5,563	4,001	14,763	-	31,349
Accumulated depreciation and depletion	2,968	-	4,653	-	4,843	-	12,464
Net capitalized costs for equity companies	4,054	-	910	4,001	9,920	-	18,885

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2019 were $19,240 million, up $2,912 million from 2018, due primarily to higher development costs, partially offset by lower acquisition costs of unproved properties. In 2018 costs were $16,328 million, down $3,316 million from 2017, due primarily to lower acquisition costs of unproved properties, partially offset by higher development costs. Total equity company costs incurred in 2019 were $2,916 million, down $115 million from 2018, due primarily to lower development costs.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
During 2019								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	12	-	-	-	26	-	38
	- Unproved	226	105	1	20	-	-	352
Exploration costs		134	1,107	155	252	111	194	1,953
Development costs		10,275	2,946	809	1,066	1,317	484	16,897
Total costs incurred for consolidated subsidiaries		10,647	4,158	965	1,338	1,454	678	19,240
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	-	-	-
Exploration costs		1	-	5	-	-	-	6
Development costs		241	-	15	69	2,585	-	2,910
Total costs incurred for equity companies		242	-	20	69	2,585	-	2,916

During 2018

Consolidated Subsidiaries

Property acquisition costs	- Proved	7	3	-	-	321	-	331
	- Unproved	238	2,109	-	1	-	-	2,348
Exploration costs		235	1,113	147	342	217	174	2,228
Development costs		7,440	1,734	96	791	1,104	256	11,421
Total costs incurred for consolidated subsidiaries		7,920	4,959	243	1,134	1,642	430	16,328

Equity Companies

Property acquisition costs	- Proved	21	-	-	-	-	-	21
	- Unproved	-	-	-	-	-	-	-
Exploration costs		1	-	4	-	5	-	10
Development costs		442	-	40	66	2,452	-	3,000
Total costs incurred for equity companies		464	-	44	66	2,457	-	3,031

During 2017

Consolidated Subsidiaries

Property acquisition costs	- Proved	88	5	-	50	583	-	726
	- Unproved	6,167	1,004	35	70	-	2,601	9,877
Exploration costs		190	702	109	373	224	509	2,107
Development costs		3,752	877	(39)	628	1,450	266	6,934
Total costs incurred for consolidated subsidiaries		10,197	2,588	105	1,121	2,257	3,376	19,644

Equity Companies

Property acquisition costs	- Proved	-	-	-	309	-	-	309
	- Unproved	-	-	-	3,111	-	-	3,111
Exploration costs		1	-	3	323	90	-	417

Development costs	137	-	41	192	1,801	-	2,171
Total costs incurred for equity companies	138	-	44	3,935	1,891	-	6,008

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2017, 2018 and 2019.

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

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

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

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

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

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

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The production and reserves reported for these types of arrangements typically vary inversely with oil and natural gas price changes. As oil and natural gas prices increase, the cash flow and value received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2019 that were associated with production sharing contract arrangements was 10 percent of liquids, 12 percent of natural gas and 10 percent on an oil-equivalent basis (natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels).

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

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

The changes between 2019 year-end proved reserves and 2018 year-end proved reserves include worldwide production of 1.5 billion oil-equivalent barrels (GOEB), a reduction of 0.2 GOEB due to the sale of non-operated assets in Norway, and other net reductions of 0.4 GOEB in the United States and Canada. Additions to proved reserves resulted from revisions in Asia of 0.3 GOEB and extensions/discoveries of 0.1 GOEB in Guyana.

The changes between 2018 year-end proved reserves and 2017 year-end proved reserves include upward revisions of 3.4 billion barrels of bitumen at Kearl as a result of improved prices; downward natural gas revisions for the Groningen field in the Netherlands; and extensions/discoveries primarily in the United States. 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. In anticipation of a lower production outlook, the Corporation reduced its estimate of proved reserves by 0.8 billion oil-equivalent barrels for the Groningen gas field.

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

	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2017	2,181	241	173	844	2,758	121	6,318	1,154	701	564	8,737
Revisions	70	19	43	30	490	2	654	(49)	416	(70)	951
Improved recovery	-	-	-	2	-	-	2	-	6	-	8
Purchases	428	5	-	-	-	-	433	164	-	-	597
Sales	(10)	-	(43)	-	-	-	(53)	(2)	-	-	(55)
Extensions/discoveries	158	161	-	3	384	-	706	58	-	-	764
Production	(132)	(16)	(54)	(150)	(136)	(13)	(501)	(67)	(111)	(21)	(700)
December 31, 2017	2,695	410	119	729	3,496	110	7,559	1,258	1,012	473	10,302
Attributable to noncontrolling interests		*10*						*3*	*288*	*144*	
Proportional interest in proved reserves of equity companies											
January 1, 2017	236	-	17	-	1,183	-	1,436	384	-	-	1,820
Revisions	29	-	(1)	-	-	-	28	4	-	-	32
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	6	-	-	6	-	-	-	6
Sales	-	-	-	-	-	-	-	-	-	-	-

Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(20)	-	(1)	-	(86)	-	(107)	(24)	-	-	(131)
December 31, 2017	245	-	15	6	1,097	-	1,363	364	-	-	1,727
Total liquids proved reserves											
at December 31, 2017	2,940	410	134	735	4,593	110	8,922	1,622	1,012	473	12,029
Net proved developed and											
undeveloped reserves of											
consolidated subsidiaries											
January 1, 2018	2,695	410	119	729	3,496	110	7,559	1,258	1,012	473	10,302
Revisions	61	28	63	(9)	4	6	153	(16)	3,286	15	3,438
Improved recovery	-	-	23	13	-	-	36	-	-	-	36
Purchases	8	-	-	-	-	-	8	2	-	-	10
Sales	(11)	-	(2)	-	-	-	(13)	(13)	-	-	(26)
Extensions/discoveries	595	113	-	9	3	-	720	238	-	-	958
Production	(144)	(22)	(37)	(138)	(146)	(11)	(498)	(65)	(113)	(22)	(698)
December 31, 2018	3,204	529	166	604	3,357	105	7,965	1,404	4,185	466	14,020
Attributable to noncontrolling interests		*44*						*4*	*962*	*142*	
Proportional interest in proved											
reserves of equity companies											
January 1, 2018	245	-	15	6	1,097	-	1,363	364	-	-	1,727
Revisions	28	-	1	-	6	-	35	1	-	-	36
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	-	-	-	1
Production	(20)	-	(1)	-	(83)	-	(104)	(23)	-	-	(127)

December 31, 2018	254	-	15	6	1,020	-	1,295	342	-	-	1,637
Total liquids proved reserves											
at December 31, 2018	3,458	529	181	610	4,377	105	9,260	1,746	4,185	466	15,657

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

	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2019	3,204	529	166	604	3,357	105	7,965	1,404	4,185	466	14,020
Revisions	(677)	(66)	20	(25)	136	-	(612)	(305)	(213)	(27)	(1,157)
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	20	-	-	-	-	-	20	12	-	-	32
Sales	(1)	-	(117)	-	-	-	(118)	(27)	-	-	(145)
Extensions/discoveries	710	125	-	-	-	-	835	263	-	-	1,098
Production	(168)	(31)	(30)	(132)	(158)	(11)	(530)	(72)	(114)	(24)	(740)
December 31, 2019	3,088	557	39	447	3,335	94	7,560	1,275	3,858	415	13,108
Attributable to noncontrolling interests		*21*						*3*	*894*	*126*	
Proportional interest in proved reserves of equity companies											
January 1, 2019	254	-	15	6	1,020	-	1,295	342	-	-	1,637
Revisions	15	-	-	-	(38)	-	(23)	3	-	-	(20)
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-

Extensions/discoveries	1	-	-	-	-	-	1	-	-	-	1
Production	(19)	-	(1)	-	(85)	-	(105)	(23)	-	-	(128)
December 31, 2019	251	-	14	6	897	-	1,168	322	-	-	1,490
Total liquids proved reserves											
at December 31, 2019	3,339	557	53	453	4,232	94	8,728	1,597	3,858	415	14,598

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ Other Americas	Canada/ Other Americas	Total
					(millions of barrels)					
Proved developed reserves, as of										
December 31, 2017										
Consolidated subsidiaries	1,489	92	119	676	2,182	131	4,689	657	473	5,819
Equity companies	208	-	14	-	1,019	-	1,241	-	-	1,241
Proved undeveloped reserves, as of										
December 31, 2017										
Consolidated subsidiaries	2,167	337	30	137	1,426	31	4,128	355	-	4,483
Equity companies	48	-	1	6	431	-	486	-	-	486
Total liquids proved reserves at										
December 31, 2017	3,912	429	164	819	5,058	162	10,544	1,012	473	12,029
Proved developed reserves, as of										
December 31, 2018										
Consolidated subsidiaries	1,696	153	123	578	2,285	118	4,953	3,880	466	9,299
Equity companies	208	-	15	-	919	-	1,142	-	-	1,142
Proved undeveloped reserves, as of										
December 31, 2018										
Consolidated subsidiaries	2,616	403	78	111	1,173	35	4,416	305	-	4,721

Equity companies	56	-	-	6	433	-	495	-	-	495
Total liquids proved reserves at										
December 31, 2018	4,576	556	216	695	4,810	153	11,006	4,185	466	15,657
Proved developed reserves, as of										
December 31, 2019										
Consolidated subsidiaries	1,655	195	23	419	2,309	90	4,691	3,528	415	8,634
Equity companies	200	-	13	-	727	-	940	-	-	940
Proved undeveloped reserves, as of										
December 31, 2019										
Consolidated subsidiaries	2,474	381	29	68	1,157	35	4,144	330	-	4,474
Equity companies	60	-	1	6	483	-	550	-	-	550
Total liquids proved reserves at										
December 31, 2019	4,389	576	66	493	4,676	125	10,325 (1)	3,858	415	14,598

(1) See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional information on natural gas liquids proved reserves see Item 2. Properties in ExxonMobil's 2019 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent Total All Products (1)
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							(millions of oil-equivalent barrels)
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2017	17,786	940	1,659	771	4,921	7,357	33,434	14,309
Revisions	649	206	134	(135)	(214)	33	673	1,063
Improved recovery	-	1	-	-	-	-	1	8
Purchases	982	56	-	-	-	-	1,038	771
Sales	(172)	(1)	(17)	-	-	-	(190)	(87)
Extensions/ discoveries	956	269	-	-	13	-	1,238	970
Production	(1,168)	(99)	(408)	(41)	(380)	(496)	(2,592)	(1,131)
December 31, 2017	19,033	1,372	1,368	595	4,340	6,894	33,602	15,903
Attributable to noncontrolling interests		*195*						
Proportional interest in proved reserves of equity companies								

January 1, 2017	211	-	7,624	-	15,234	-	23,069	5,665
Revisions	25	-	(1,129)	-	86	-	(1,018)	(138)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	914	-	-	914	158
Sales	-	-	-	-	-	-	-	-
Extensions/ discoveries	-	-	-	-	-	-	-	-
Production	(13)	-	(331)	-	(1,072)	-	(1,416)	(367)
December 31, 2017	223	-	6,164	914	14,248	-	21,549	5,318
Total proved reserves at December 31, 2017	19,256	1,372	7,532	1,509	18,588	6,894	55,151	21,221
Net proved developed and undeveloped								
reserves of consolidated subsidiaries								
January 1, 2018	19,033	1,372	1,368	595	4,340	6,894	33,602	15,903
Revisions	(98)	(29)	306	38	(147)	1,065	1,135	3,626
Improved recovery	-	-	-	-	-	-	-	36
Purchases	104	-	-	-	-	-	104	27
Sales	(264)	(3)	(4)	-	-	-	(271)	(71)
Extensions/ discoveries	3,658	506	3	-	1	7	4,175	1,654
Production	(1,030)	(102)	(361)	(45)	(353)	(504)	(2,395)	(1,097)
December 31, 2018	21,403	1,744	1,312	588	3,841	7,462	36,350	20,078

Attributable to noncontrolling interests

Proportional interest in proved reserves								
of equity companies								
January 1, 2018	223	-	6,164	914	14,248	-	21,549	5,318
Revisions	12	-	(4,801)	(51)	102	-	(4,738)	(753)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	(38)	-	-	-	(38)	(6)
Extensions/ discoveries	2	-	-	-	-	-	2	1
Production	(12)	-	(268)	-	(1,029)	-	(1,309)	(345)
December 31, 2018	225	-	1,057	863	13,321	-	15,466	4,215
Total proved reserves at December 31, 2018	21,628	1,744	2,369	1,451	17,162	7,462	51,816	24,293

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent Total All Products *(1)*
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2019	21,403	1,744	1,312	588	3,841	7,462	36,350	20,078
Revisions	(3,213)	(301)	41	(171)	953	39	(2,652)	(1,599)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	85	-	-	-	-	-	85	47
Sales	(297)	(29)	(416)	-	-	-	(742)	(269)
Extensions/ discoveries	2,151	166	-	-	-	-	2,317	1,484
Production	(1,103)	(114)	(316)	(40)	(361)	(500)	(2,434)	(1,145)
December 31, 2019	19,026	1,466	621	377	4,433	7,001	32,924	18,596
Attributable to noncontrolling interests		*256*						
Proportional interest in proved reserves of equity companies								

January 1, 2019	225	-	1,057	863	13,321	-	15,466		4,215
Revisions	(1)	-	(238)	45	142	-	(52)		(29)
Improved recovery	-	-	-	-	-	-	-		-
Purchases	-	-	-	-	-	-	-		-
Sales	-	-	-	-	-	-	-		-
Extensions/ discoveries	1	-	-	-	-	-	1		1
Production	(12)	-	(238)	-	(1,009)	-	(1,259)		(338)
December 31, 2019	213	-	581	908	12,454	-	14,156		3,849
Total proved reserves at December 31, 2019	19,239	1,466	1,202	1,285	16,887	7,001	47,080		22,445

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	**Total All Products *(1)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Proved developed reserves, as of								
December 31, 2017								
Consolidated subsidiaries	12,649	512	1,231	584	4,030	4,420	23,426	9,724
Equity companies	154	-	4,899	-	12,898	-	17,951	4,232
Proved undeveloped reserves, as of								
December 31, 2017								
Consolidated subsidiaries	6,384	860	137	11	310	2,474	10,176	6,179
Equity companies	69	-	1,265	914	1,350	-	3,598	1,086
Total proved reserves at December 31, 2017	19,256	1,372	7,532	1,509	18,588	6,894	55,151	21,221
Proved developed reserves, as of								
December 31, 2018								
Consolidated subsidiaries	12,538	605	1,116	581	3,618	4,336	22,794	13,098
Equity companies	152	-	988	-	11,951	-	13,091	3,324
Proved undeveloped reserves, as of								
December 31, 2018								
Consolidated subsidiaries	8,865	1,139	196	7	223	3,126	13,556	6,980

Equity companies	73	-	69	863	1,370	-	2,375	891
Total proved reserves at December 31, 2018	21,628	1,744	2,369	1,451	17,162	7,462	51,816	24,293
Proved developed reserves, as of								
December 31, 2019								
Consolidated subsidiaries	11,882	613	502	377	3,508	3,765	20,647	12,075
Equity companies	143	-	505	-	9,859	-	10,507	2,691
Proved undeveloped reserves, as of								
December 31, 2019								
Consolidated subsidiaries	7,144	853	119	-	925	3,236	12,277	6,521
Equity companies	70	-	76	908	2,595	-	3,649	1,158
Total proved reserves at December 31, 2019	19,239	1,466	1,202	1,285	16,887	7,001	47,080	22,445

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

Standardized Measure of Discounted Future Cash Flows

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

Standardized Measure of Discounted Future Cash Flows	**United States**	**Canada/ Other Americas** *(1)*	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
			(millions of dollars)				
Consolidated Subsidiaries							
As of December 31, 2017							
Future cash inflows from sales of oil and gas	186,126	78,870	14,794	43,223	191,254	40,814	555,081
Future production costs	78,980	42,280	4,424	14,049	53,723	8,424	201,880
Future development costs	39,996	18,150	7,480	8,897	15,156	7,951	97,630
Future income tax expenses	12,879	4,527	2,790	8,818	90,614	6,017	125,645
Future net cash flows	54,271	13,913	100	11,459	31,761	18,422	129,926
Effect of discounting net cash flows at 10%	30,574	6,158	(1,255)	2,996	17,511	8,741	64,725
Discounted future net cash flows	23,697	7,755	1,355	8,463	14,250	9,681	65,201
Equity Companies							
As of December 31, 2017							
Future cash inflows from sales of oil and gas	12,643	-	28,557	2,366	127,364	-	170,930
Future production costs	5,927	-	21,120	247	48,300	-	75,594
Future development costs	3,012	-	1,913	417	11,825	-	17,167

Future income tax expenses	-	-	1,683	514	22,396	-	24,593
Future net cash flows	3,704	-	3,841	1,188	44,843	-	53,576
Effect of discounting net cash flows at 10%	1,668	-	2,116	1,045	23,744	-	28,573
Discounted future net cash flows	2,036	-	1,725	143	21,099	-	25,003
Total consolidated and equity interests in standardized measure of discounted future net cash flows	25,733	7,755	3,080	8,606	35,349	9,681	90,204

(1) Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $1,016 million in 2017.

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ Other Americas *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
			(millions of dollars)				
Consolidated Subsidiaries							
As of December 31, 2018							
Future cash inflows from sales of oil and gas	265,527	204,596	23,263	47,557	241,410	67,041	849,394
Future production costs	96,489	125,469	5,023	16,019	61,674	18,081	322,755
Future development costs	54,457	29,759	7,351	8,356	13,907	8,047	121,877
Future income tax expenses	25,365	9,024	8,255	10,491	124,043	10,499	187,677
Future net cash flows	89,216	40,344	2,634	12,691	41,786	30,414	217,085
Effect of discounting net cash flows at 10%	49,176	22,315	(6)	2,957	21,509	15,030	110,981
Discounted future net cash flows	40,040	18,029	2,640	9,734	20,277	15,384	106,104
Equity Companies							
As of December 31, 2018							
Future cash inflows from sales of oil and gas	17,730	-	7,264	3,777	165,471	-	194,242
Future production costs	6,474	-	2,157	249	61,331	-	70,211
Future development costs	3,359	-	1,165	370	10,295	-	15,189
Future income tax expenses	-	-	1,612	964	30,662	-	33,238
Future net cash flows	7,897	-	2,330	2,194	63,183	-	75,604
Effect of discounting net cash flows at 10%	4,104	-	713	1,712	31,503	-	38,032
Discounted future net cash flows	3,793	-	1,617	482	31,680	-	37,572

Total consolidated and equity interests in

standardized measure of discounted

future net cash flows	43,833	18,029	4,257	10,216	51,957	15,384	143,676

Consolidated Subsidiaries							
As of December 31, 2019							
Future cash inflows from sales of oil and gas	208,981	190,604	5,789	30,194	215,837	43,599	695,004
Future production costs	90,448	133,606	3,209	10,177	58,255	12,980	308,675
Future development costs	53,641	31,158	4,397	6,756	14,113	8,109	118,174
Future income tax expenses	12,530	5,888	(594)	5,374	108,316	5,158	136,672
Future net cash flows	52,362	19,952	(1,223)	7,887	35,153	17,352	131,483
Effect of discounting net cash flows at 10%	30,499	7,728	(1,265)	872	18,658	7,491	63,983
Discounted future net cash flows	21,863	12,224	42	7,015	16,495	9,861	67,500

Equity Companies							
As of December 31, 2019							
Future cash inflows from sales of oil and gas	15,729	-	3,194	2,509	115,451	-	136,883
Future production costs	6,848	-	1,302	246	48,259	-	56,655
Future development costs	3,681	-	1,182	247	11,463	-	16,573
Future income tax expenses	-	-	346	555	17,891	-	18,792
Future net cash flows	5,200	-	364	1,461	37,838	-	44,863
Effect of discounting net cash flows at 10%	2,721	-	41	1,112	18,573	-	22,447
Discounted future net cash flows	2,479	-	323	349	19,265	-	22,416

Total consolidated and equity interests in							
standardized measure of discounted							
future net cash flows	24,342	12,224	365	7,364	35,760	9,861	89,916

(1) Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $2,823 million in 2018 and $1,064 million in 2019.

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

Consolidated and Equity Interests	**2017**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2016	35,150	18,201	53,351
Value of reserves added during the year due to extensions, discoveries,			
improved recovery and net purchases less related costs	10,375	255	10,630
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of			
production (lifting) costs	(24,911)	(7,358)	(32,269)
Development costs incurred during the year	7,066	2,020	9,086
Net change in prices, lifting and development costs	51,703	12,782	64,485
Revisions of previous reserves estimates	6,580	1,193	7,773
Accretion of discount	4,951	2,124	7,075
Net change in income taxes	(25,713)	(4,214)	(29,927)
Total change in the standardized measure during the year	30,051	6,802	36,853
Discounted future net cash flows as of December 31, 2017	65,201	25,003	90,204

Consolidated and Equity Interests	2018		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2017	65,201	25,003	90,204
Value of reserves added during the year due to extensions, discoveries,			
improved recovery and net purchases less related costs	9,472	(134)	9,338
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of			
production (lifting) costs	(31,706)	(9,956)	(41,662)
Development costs incurred during the year	11,500	2,762	14,262
Net change in prices, lifting and development costs	56,798	23,582	80,380
Revisions of previous reserves estimates	14,515	(2,091)	12,424
Accretion of discount	8,793	3,043	11,836
Net change in income taxes	(28,469)	(4,637)	(33,106)
Total change in the standardized measure during the year	40,903	12,569	53,472
Discounted future net cash flows as of December 31, 2018	106,104	37,572	143,676

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

Consolidated and Equity Interests (continued)		**2019**	
			Total
		Share of	**Consolidated**
	Consolidated	**Equity Method**	**and Equity**
	Subsidiaries	**Investees**	**Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2018	106,104	37,572	143,676
Value of reserves added during the year due to extensions, discoveries,			
improved recovery and net purchases/sales less related costs	(1,252)	4	(1,248)
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of			
production (lifting) costs	(29,159)	(8,202)	(37,361)
Development costs incurred during the year	16,544	2,927	19,471
Net change in prices, lifting and development costs	(66,455)	(21,046)	(87,501)
Revisions of previous reserves estimates	4,906	657	5,563
Accretion of discount	11,433	3,956	15,389
Net change in income taxes	25,379	6,548	31,927
Total change in the standardized measure during the year	(38,604)	(15,156)	(53,760)
Discounted future net cash flows as of December 31, 2019	67,500	22,416	89,916

OPERATING INFORMATION (unaudited)

	2019	2018	2017	2016	2015
Production of crude oil, natural gas liquids, bitumen and synthetic oil					
Net production	*(thousands of barrels daily)*				
United States	646	551	514	494	476
Canada/Other Americas	467	438	412	430	402
Europe	108	132	182	204	204
Africa	372	387	423	474	529
Asia	748	711	698	707	684
Australia/Oceania	45	47	54	56	50
Worldwide	2,386	2,266	2,283	2,365	2,345
Natural gas production available for sale					
Net production	*(millions of cubic feet daily)*				
United States	2,778	2,574	2,936	3,078	3,147
Canada/Other Americas	258	227	218	239	261
Europe	1,457	1,653	1,948	2,173	2,286
Africa	7	13	5	7	5
Asia	3,575	3,613	3,794	3,743	4,139
Australia/Oceania	1,319	1,325	1,310	887	677
Worldwide	9,394	9,405	10,211	10,127	10,515
	(thousands of oil-equivalent barrels daily)				
Oil-equivalent production *(1)*	3,952	3,833	3,985	4,053	4,097
Refinery throughput	*(thousands of barrels daily)*				
United States	1,532	1,588	1,508	1,591	1,709
Canada	353	392	383	363	386

Europe	1,317	1,422	1,510	1,417	1,496
Asia Pacific	598	706	690	708	647
Other Non-U.S.	181	164	200	190	194
Worldwide	3,981	4,272	4,291	4,269	4,432
Petroleum product sales *(2)*					
United States	2,292	2,210	2,190	2,250	2,521
Canada	476	510	499	491	488
Europe	1,479	1,556	1,597	1,519	1,542
Asia Pacific and other Eastern Hemisphere	1,156	1,200	1,164	1,140	1,124
Latin America	49	36	80	82	79
Worldwide	5,452	5,512	5,530	5,482	5,754
Gasoline, naphthas	2,220	2,217	2,262	2,270	2,363
Heating oils, kerosene, diesel oils	1,867	1,840	1,850	1,772	1,924
Aviation fuels	406	402	382	399	413
Heavy fuels	270	395	371	370	377
Specialty petroleum products	689	658	665	671	677
Worldwide	5,452	5,512	5,530	5,482	5,754
Chemical prime product sales *(2)*	*(thousands of metric tons)*				
United States	9,127	9,824	9,307	9,576	9,664
Non-U.S.	17,389	17,045	16,113	15,349	15,049
Worldwide	26,516	26,869	25,420	24,925	24,713

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

(1) 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.

INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the Registrant's Annual Report on Form 10-K for 2015).
3(ii)	By-Laws, as revised effective November 1, 2017 (incorporated by reference to Exhibit 3(ii) to the Registrant's Report on Form 8-K of October 31, 2017).
4(vi)	Description of ExxonMobil Capital Stock.
10(iii)(a.1)	2003 Incentive Program, as approved by shareholders May 28, 2003 (incorporated by reference to Exhibit 10(iii)(a.1) to the Registrant's Annual Report on Form 10-K for 2017).*
10(iii)(a.2)	Extended Provisions for Restricted Stock Agreements (incorporated by reference to Exhibit 10(iii)(a.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements – Settlement in Shares.*
10(iii)(b.1)	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 10(iii)(b.1) to the Registrant's Annual Report on Form 10-K for 2018).*
10(iii)(b.2)	Earnings Bonus Unit instrument.*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant's Annual Report on Form 10-K for 2014).*
10(iii)(c.3)	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant's Annual Report on Form 10-K for 2018).*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f.1) to the Registrant's Annual Report on Form 10-K for 2018).*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by reference to Exhibit 10(iii)(f.2) to the Registrant's Annual Report on Form 10-K for 2016).*

10(iii)(f.3) Form of restricted stock grant letter for non-employee directors.*

10(iii)(f.4) Standing resolution for non-employee director cash fees dated October 26, 2011 (incorporated by reference to Exhibit 10(iii)(f.4) to the Registrant's Annual Report on Form 10-K for 2015).*

14 Code of Ethics and Business Conduct (incorporated by reference to Exhibit 14 to the Registrant's Annual Report on Form 10-K for 2017).

21 Subsidiaries of the registrant.

23 Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.

31.1 Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.

31.2 Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Financial Officer.

31.3 Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting Officer.

32.1 Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.

32.2 Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Financial Officer.

32.3 Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.

101 Interactive data files (formatted as Inline XBRL).

104 Cover page interactive data file (formatted as Inline XBRL and contained in Exhibit 101).

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

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

SIGNATURES

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

EXXON MOBIL CORPORATION

By: /s/ DARREN W. WOODS
(Darren W. Woods,
Chairman of the Board)

Dated February 26, 2020

POWER OF ATTORNEY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated and on February 26, 2020.

/s/ DARREN W. WOODS (Darren W. Woods)	Chairman of the Board (Principal Executive Officer)
/s/ SUSAN K. AVERY (Susan K. Avery)	Director
/s/ ANGELA F. BRALY (Angela F. Braly)	Director

/s/ URSULA M. BURNS (Ursula M. Burns)	Director

/s/ KENNETH C. FRAZIER	Director
(Kenneth C. Frazier)	
/s/ JOSEPH L. HOOLEY	Director
(Joseph L. Hooley)	
/s/ STEVEN A. KANDARIAN	Director
(Steven A. Kandarian)	
/s/ DOUGLAS R. OBERHELMAN	Director
(Douglas R. Oberhelman)	
/s/ SAMUEL J. PALMISANO	Director
(Samuel J. Palmisano)	
/s/ STEVEN S REINEMUND	Director
(Steven S Reinemund)	
/s/ WILLIAM C. WELDON	Director
(William C. Weldon)	
/s/ ANDREW P. SWIGER	Senior Vice President
(Andrew P. Swiger)	(Principal Financial Officer)
/s/ DAVID S. ROSENTHAL	Vice President and Controller
(David S. Rosenthal)	(Principal Accounting Officer)

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

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 940-6000

(Registrant’s telephone number, including area code)

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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

PART II

PART I

ITEM 1. BUSINESS

Exxon Mobil Corporation was incorporated in the State of New Jersey in 1882. Divisions and affiliated companies of ExxonMobil operate or market products in the United States and most other countries of the world. Their principal business 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. 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_2 emissions from gas-fired power plants. Our future results may depend in part on the success of our research efforts and on our ability to adapt and apply the strengths of our current business model to providing the energy products of the future in a cost-competitive manner. See “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.

	Crude Oil	Natural Gas Liquids	Bitumen	Synthetic Oil	Natural Gas	Oil-Equivalent Total All Products
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million bbls)*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
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
Equity Companies						
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
Undeveloped						
Consolidated Subsidiaries						
United States	1,947	669	-	-	8,865	4,093
Canada/Other Americas *(1)*	385	18	305	-	1,139	898
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
Equity Companies						
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

Total Proved Reserves	9,260	1,746	4,185	466	51,816	24,293

(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	
	(thousands of barrels daily)					
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries						
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
Equity Companies						
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
Total crude oil and natural gas liquids production	1,648	248	1,666	255	1,742	252
Bitumen production						
Consolidated Subsidiaries						
Canada/Other Americas	310		305		304	
Synthetic oil production						
Consolidated Subsidiaries						
Canada/Other Americas	60		57		67	
Total liquids production	2,266		2,283		2,365	
	(millions of cubic feet daily)					
Natural gas production available for sale						
Consolidated Subsidiaries						
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	
Total Consolidated Subsidiaries	5,878		6,395		6,205	
Equity Companies						
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	
Total natural gas production available for sale	9,405		10,211		10,127	

	(thousands of oil-equivalent barrels daily)		
Oil-equivalent production	3,833	3,985	4,053

(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.

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2018				*(dollars per unit)*			
Consolidated Subsidiaries							
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
Equity Companies							
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
Total							
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
During 2017							
Consolidated Subsidiaries							
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
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
During 2016				(dollars per unit)			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	36.47	39.50	40.57	42.59	41.89	43.33	40.59
NGL, per barrel	16.16	18.91	22.17	26.78	17.12	23.95	18.99
Natural gas, per thousand cubic feet	1.43	1.71	4.26	1.14	1.56	3.46	2.25
Bitumen, per barrel	-	19.30	-	-	-	-	19.30
Synthetic oil, per barrel	-	43.03	-	-	-	-	43.03
Average production costs, per oil-equivalent barrel - total	10.41	21.16	12.78	12.75	6.44	7.12	11.79
Average production costs, per barrel - bitumen	-	18.25	-	-	-	-	18.25
Average production costs, per barrel - synthetic oil	-	33.64	-	-	-	-	33.64
Equity Companies							
Average production prices							
Crude oil, per barrel	38.44	-	36.13	-	39.69	-	39.41
NGL, per barrel	14.85	-	-	-	25.21	-	24.87
Natural gas, per thousand cubic feet	2.03	-	4.19	-	3.59	-	3.75
Average production costs, per oil-equivalent barrel - total	22.26	-	7.92	-	1.80	-	4.21
Total							
Average production prices							
Crude oil, per barrel	36.75	39.50	40.51	42.59	41.06	43.33	40.39
NGL, per barrel	16.13	18.91	22.17	26.78	22.85	23.95	20.56
Natural gas, per thousand cubic feet	1.44	1.71	4.22	1.14	3.09	3.46	2.83
Bitumen, per barrel	-	19.30	-	-	-	-	19.30
Synthetic oil, per barrel	-	43.03	-	-	-	-	43.03
Average production costs, per oil-equivalent barrel - total	11.18	21.16	11.21	12.75	3.77	7.12	9.89
Average production costs, per barrel - bitumen	-	18.25	-	-	-	-	18.25
Average production costs, per barrel - synthetic oil	-	33.64	-	-	-	-	33.64

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

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

	2018	2017	2016
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
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
Equity Companies			
United States	168	154	121
Europe	3	1	2
Africa	-	-	-
Asia	6	3	3
Total Equity Companies	177	158	126
Total productive development wells drilled	616	498	503
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	4	4	2
Canada/Other Americas	1	-	-
Europe	-	1	2
Africa	1	-	-
Asia	-	-	-
Australia/Oceania	-	-	-
Total Consolidated Subsidiaries	6	5	4
Equity Companies			
United States	-	-	-
Europe	-	-	-
Africa	-	-	-
Asia	-	-	-
Total Equity Companies	-	-	-
Total dry development wells drilled	6	5	4
Total number of net wells drilled	635	512	514

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
Wells Drilling				
Consolidated Subsidiaries				
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
Equity Companies				
United States	7	1	10	1
Europe	1	1	8	3
Asia	17	4	14	4
Total Equity Companies	25	6	32	8
Total gross and net wells drilling	1,135	549	965	384

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
Gross and Net Productive Wells								
Consolidated Subsidiaries								
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
Equity Companies								
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
Total gross and net productive wells	43,050	19,837	35,428	17,218	43,281	19,457	37,833	18,727

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

	Year-End 2018		Year-End 2017	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
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
Equity Companies				
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
Total gross and net developed acreage	33,793	16,186	34,875	16,889

(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

	Year-End 2018		Year-End 2017	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
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
Equity Companies				
United States	203	76	207	77
Europe	100	25	100	25
Africa	596	149	596	149
Asia	73	5	191,147	63,633
Total Equity Companies	972	255	192,050	63,884
Total gross and net undeveloped acreage	119,581	60,933	296,104	124,915

(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)*

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

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest %
North America						
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	
Europe						
Antwerp	Belgium	-	0.4	-	-	100
Fife	United Kingdom	0.4	-	-	-	50
Gravenchon	France	0.4	0.4	0.3	-	100
Meerhout	Belgium	-	0.5	-	-	100
Rotterdam	Netherlands	-	-	-	0.7	100
Total Europe		0.8	1.3	0.3	0.7	
Middle East						
Al Jubail	Saudi Arabia	0.6	0.7	-	-	50
Yanbu	Saudi Arabia	1.0	0.7	0.2	-	50
Total Middle East		1.6	1.4	0.2	-	
Asia Pacific						
Fujian	China	0.3	0.2	0.2	0.2	25
Singapore	Singapore	1.9	1.9	0.9	1.8	100
Sriracha	Thailand	-	-	-	0.5	66
Total Asia Pacific		2.2	2.1	1.1	2.5	
Total Worldwide		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)

Darren W. Woods *Chairman of the Board*

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.

Neil A. Chapman *Senior Vice President*

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.

Andrew P. Swiger *Senior Vice President*

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.

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

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.

Peter P. Clarke *Vice President*

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.

Bradley W. Corson *Vice President*

Held current title since: March 1, 2015 Age: 57

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.

Neil W. Duffin *Vice President*

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.

Randall M. Ebner *Vice President and General Counsel*

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.

Stephen M. Greenlee *Vice President*

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.

Neil A. Hansen *Vice President – Investor Relations and Secretary*

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.

Liam M. Mallon *President, ExxonMobil Development Company*

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.

Bryan W. Milton *Vice President*

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.

Sara N. Ortwein *President, XTO Energy Inc., a subsidiary of the Corporation*

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.

David S. Rosenthal	*Vice President and Controller*	
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.

Robert N. Schleckser *Vice President and Treasurer*

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.

James M. Spellings, Jr. *Vice President and General Tax Counsel*

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.

John R. Verity *Vice President*

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.

Theodore J. Wojnar, Jr. *Vice President – Corporate Strategic Planning*

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
	(millions of dollars, except per share amounts)				
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

Plan Category	*(a)* Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	*(b)* Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	*(c)* Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	39,847,820 *(1)*	-	82,918,471 *(2)(3)*
Equity compensation plans not approved by security holders	-	-	-
Total	39,847,820	-	82,918,471

(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

Financial	Earnings After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
	2018	2017	2018	2017	2018	2017	2018	2017
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
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.

Operating	2018	2017		2018	2017
	(thousands of barrels daily)			*(thousands of barrels daily)*	
Net liquids production			Refinery throughput		
United States	551	514	United States	1,588	1,508
Non-U.S.	1,715	1,769	Non-U.S.	2,684	2,783
Total	2,266	2,283	Total	4,272	4,291
	(millions of cubic feet daily)			*(thousands of barrels daily)*	
Natural gas production available for sale			Petroleum product sales *(2)*		
United States	2,574	2,936	United States	2,210	2,190
Non-U.S.	6,831	7,275	Non-U.S.	3,302	3,340
Total	9,405	10,211	Total	5,512	5,530
	(thousands of oil-equivalent barrels daily)			*(thousands of metric tons)*	
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

	2018	2017	2016	2015	2014
	(millions of dollars, except where stated otherwise)				
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.

Cash flow from operations and asset sales	**2018**	**2017**	**2016**
	(millions of dollars)		
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.

Capital employed	**2018**	**2017**	**2016**
	(millions of dollars)		
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)
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

FREQUENTLY USED TERMS

Return on Average Capital Employed

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

Return on average capital employed	**2018**	**2017**	**2016**
		(millions of dollars)	
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
Volumes										
Production of crude oil,	*(thousands of barrels daily)*									
natural gas liquids, synthetic oil and bitumen	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	*(millions of cubic feet daily)*									
available for sale	10,038	8,613	9,001	9,974	9,405	10,908	9,920	9,585	10,441	10,211
	(thousands of oil-equivalent barrels daily)									
Oil-equivalent production *(2)*	3,889	3,647	3,786	4,010	3,833	4,151	3,922	3,878	3,991	3,985
	(thousands of metric tons)									
Chemical prime product sales *(1)*	6,668	6,852	6,677	6,672	26,869	6,072	6,120	6,446	6,782	25,420
Summarized financial data										
Sales and other operating	*(millions of dollars)*									
revenue	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
Per share data	*(dollars per share)*									
Earnings per common share *(5)*	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	2018	2017	2016
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
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_2 emissions is assumed to reach about $80 per tonne on average in 2040 in OECD nations. China and other leading non-OECD nations are expected to trail OECD policy initiatives. Nevertheless, as people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need.

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.

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

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

Upstream

	2018	2017	2016
		(millions of dollars)	
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.

Upstream Additional Information

	2018	2017
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production) *(1)*		
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.

Downstream

	2018	2017	2016
		(millions of dollars)	
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.

Chemical

	2018	2017	2016
		(millions of dollars)	
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

	2018	2017	2016
		(millions of dollars)	
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
		(millions of dollars)	
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)
		(December 31)	
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.

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.

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.

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.

		Payments Due by Period				
Commitments	**Note Reference Number**	**2019**	**2020-2021**	**2022-2023**	**2024 and Beyond**	**Total**
			(millions of dollars)			
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.

	2018	2017	2016
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		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
	(millions of dollars)					
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
Total	10,668	15,255	25,923	6,212	16,868	23,080

(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.

TAXES

	2018	2017	2016
		(millions of dollars)	
Income taxes	9,532	(1,174)	(406)
Effective income tax rate	*37%*	*5%*	*13%*
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

	2018	2017
	(millions of dollars)	
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

Worldwide Average Realizations *(1)*	2018	2017	2016
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.

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.

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

	Note Reference Number	2018	2017	2016
		(millions of dollars)		
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 *(dollars)*	12	4.88	4.63	1.88
Earnings per common share - assuming dilution *(dollars)*	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

	2018	2017	2016
	(millions of dollars)		
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

	Note Reference Number	Dec. 31 2018	Dec. 31 2017
		(millions of dollars)	
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		10,332	9,767
Total assets		346,196	348,691
Liabilities			
Current liabilities			
Notes and loans payable	6	17,258	17,930
Accounts payable and accrued liabilities	6	37,268	36,796
Income taxes payable		2,612	3,045
Total current liabilities		57,138	57,771
Long-term debt	14	20,538	24,406
Postretirement benefits reserves	17	20,272	21,132
Deferred income tax liabilities	19	27,244	26,893
Long-term obligations to equity companies		4,382	4,774
Other long-term obligations		18,094	19,215
Total liabilities		147,668	154,191
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		15,258	14,656
Earnings reinvested		421,653	414,540
Accumulated other comprehensive income		(19,564)	(16,262)
Common stock held in treasury (3,782 million shares in 2018 and 3,780 million shares in 2017)		(225,553)	(225,246)
ExxonMobil share of equity		191,794	187,688
Noncontrolling interests		6,734	6,812
Total equity		198,528	194,500
Total liabilities and equity		346,196	348,691

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2018	2017	2016
		(millions of dollars)		
Cash flows from operating activities				
Net income including noncontrolling interests		21,421	19,848	8,375
Adjustments for noncash transactions				
Depreciation and depletion	9	18,745	19,893	22,308
Deferred income tax charges/(credits)		(60)	(8,577)	(4,386)
Postretirement benefits expense in excess of/(less than) net payments		1,070	1,135	(329)
Other long-term obligation provisions in excess of/(less than) payments		(68)	(610)	(19)
Dividends received greater than/(less than) equity in current earnings of equity companies		(1,684)	131	(579)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		(545)	(3,954)	(2,090)
- Inventories		(3,107)	(1,682)	(388)
- Other current assets		(25)	(117)	171
Increase/(reduction) - Accounts and other payables		2,321	5,104	915
Net (gain) on asset sales	5	(1,993)	(334)	(1,682)
All other items - net		(61)	(771)	(214)
Net cash provided by operating activities		36,014	30,066	22,082
Cash flows from investing activities				
Additions to property, plant and equipment		(19,574)	(15,402)	(16,163)
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments		4,123	3,103	4,275
Additional investments and advances		(1,981)	(5,507)	(1,417)
Other investing activities including collection of advances		986	2,076	902
Net cash used in investing activities		(16,446)	(15,730)	(12,403)
Cash flows from financing activities				
Additions to long-term debt		46	60	12,066
Additions to short-term debt		-	1,735	-
Reductions in short-term debt		(4,752)	(5,024)	(314)
Additions/(reductions) in commercial paper, and debt with three months or less maturity	5	(219)	2,181	(7,459)
Cash dividends to ExxonMobil shareholders		(13,798)	(13,001)	(12,453)
Cash dividends to noncontrolling interests		(243)	(184)	(162)
Changes in noncontrolling interests		146	(150)	-
Common stock acquired		(626)	(747)	(977)
Common stock sold		-	-	6
Net cash used in financing activities		(19,446)	(15,130)	(9,293)
Effects of exchange rate changes on cash		(257)	314	(434)
Increase/(decrease) in cash and cash equivalents		(135)	(480)	(48)
Cash and cash equivalents at beginning of year		3,177	3,657	3,705
Cash and cash equivalents at end of year		3,042	3,177	3,657

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	Total Equity
	(millions of dollars)						
Balance as of December 31, 2015	11,612	412,444	(23,511)	(229,734)	170,811	5,999	176,810
Amortization of stock-based awards	796	-	-	-	796	-	796
Tax benefits related to stock-based awards	30	-	-	-	30	-	30
Other	(281)	-	-	-	(281)	-	(281)
Net income for the year	-	7,840	-	-	7,840	535	8,375
Dividends - common shares	-	(12,453)	-	-	(12,453)	(162)	(12,615)
Other comprehensive income	-	-	1,272	-	1,272	133	1,405
Acquisitions, at cost	-	-	-	(977)	(977)	-	(977)
Dispositions	-	-	-	287	287	-	287
Balance as of December 31, 2016	12,157	407,831	(22,239)	(230,424)	167,325	6,505	173,830
Amortization of stock-based awards	801	-	-	-	801	-	801
Other	(380)	-	-	-	(380)	(52)	(432)
Net income for the year	-	19,710	-	-	19,710	138	19,848
Dividends - common shares	-	(13,001)	-	-	(13,001)	(184)	(13,185)
Other comprehensive income	-	-	5,977	-	5,977	555	6,532
Acquisitions, at cost	-	-	-	(828)	(828)	(150)	(978)
Issued for acquisitions	2,078	-	-	5,711	7,789	-	7,789
Dispositions	-	-	-	295	295	-	295
Balance as of December 31, 2017	14,656	414,540	(16,262)	(225,246)	187,688	6,812	194,500
Amortization of stock-based awards	758	-	-	-	758	-	758
Other	(156)	-	-	-	(156)	436	280
Net income for the year	-	20,840	-	-	20,840	581	21,421
Dividends - common shares	-	(13,798)	-	-	(13,798)	(243)	(14,041)
Cumulative effect of accounting change	-	71	(39)	-	32	15	47
Other comprehensive income	-	-	(3,263)	-	(3,263)	(407)	(3,670)
Acquisitions, at cost	-	-	-	(626)	(626)	(460)	(1,086)
Dispositions	-	-	-	319	319	-	319
Balance as of December 31, 2018	15,258	421,653	(19,564)	(225,553)	191,794	6,734	198,528

Common Stock Share Activity	Issued	Held in Treasury	Outstanding
		(millions of shares)	
Balance as of December 31, 2015	8,019	(3,863)	4,156
Acquisitions	-	(12)	(12)
Dispositions	-	4	4
Balance as of December 31, 2016	8,019	(3,871)	4,148
Acquisitions	-	(10)	(10)
Issued for acquisitions	-	96	96
Dispositions	-	5	5
Balance as of December 31, 2017	8,019	(3,780)	4,239
Acquisitions	-	(8)	(8)
Dispositions	-	6	6
Balance as of December 31, 2018	8,019	(3,782)	4,237

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

The Corporation's principal business 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.

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years' data has been reclassified in certain cases to conform to the 2018 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation and Accounting for Investments

The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses. Amounts representing the Corporation's interest in entities that it does not control, but over which it exercises significant influence, are included in "Investments, advances and long-term receivables". The Corporation's share of the net income of these companies is included in the Consolidated Statement of Income caption "Income from equity affiliates".

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

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

Investments in equity securities other than consolidated subsidiaries and equity method investments are measured at fair value with changes in fair value recognized in net income. The Corporation uses the modified approach for equity securities that do not have a readily determinable fair value. This modified approach measures investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions in a similar investment of the same issuer.

The Corporation's share of the cumulative foreign exchange translation adjustment for equity method investments is reported in "Accumulated other comprehensive income".

Revenue Recognition

The Corporation generally sells crude oil, natural gas and petroleum and chemical products under short-term agreements at prevailing market prices. In some cases (e.g., natural gas), products may be sold under long-term agreements, with periodic price adjustments to reflect market conditions. Revenue is recognized at the amount the Corporation expects to receive when the customer has taken control, which is typically when title transfers and the customer has assumed the risks and rewards of ownership. The prices of certain sales are based on price indices that are sometimes not available until the next period. In such cases, estimated realizations are accrued when the sale is recognized, and are finalized when the price is available. Such adjustments to revenue from performance obligations satisfied in previous periods are not significant. Payment for revenue transactions is typically due within 30 days. Future volume delivery obligations that are unsatisfied at the end of the period are expected to be fulfilled through ordinary production or purchases. These performance obligations are based on market prices at the time of the transaction and are fully constrained due to market price volatility.

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

“Sales and other operating revenue” and “Notes and accounts receivable” primarily arise from contracts with customers. Long-term receivables are primarily from non-customers. Contract assets are mainly from marketing assistance programs and are not significant. Contract liabilities are mainly customer prepayments and accruals of expected volume discounts and are not significant.

Income and Other Taxes

The Corporation excludes from the Consolidated Statement of Income certain sales and value-added taxes imposed on and concurrent with revenue-producing transactions with customers and collected on behalf of governmental authorities. Similar taxes, for which the Corporation is not considered to be an agent for the government, are reported on a gross basis (included in both "Sales and other operating revenue" and "Other taxes and duties").

The Corporation accounts for U.S. tax on global intangible low-taxed income as an income tax expense in the period in which it is incurred. We have elected not to adopt an option provided by the Financial Accounting Standards Board Update, *Income Statement – Reporting Comprehensive Income: Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.* The option allowed the reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act.

Derivative Instruments

The Corporation may use derivative instruments for trading purposes and to offset exposures associated with commodity prices, foreign currency exchange rates and interest rates that arise from existing assets, liabilities and forecasted transactions. All derivative instruments are recorded at fair value. Derivative assets and liabilities with the same counterparty are netted if the right of offset exists and certain other criteria are met. Collateral payables or receivables are netted against derivative assets and derivative liabilities, respectively.

Recognition and classification of the gain or loss that results from adjusting a derivative to fair value depends on the purpose for the derivative. All gains and losses from derivative instruments for which the Corporation does not apply hedge accounting are immediately recognized in earnings. We may designate derivatives as fair value or cash flow hedges. For fair value hedges, the gain or loss from derivative instruments and the offsetting gain or loss from the hedged item are recognized in earnings. For cash flow hedges, the effective portion of the gain or loss from the derivative instrument is initially reported as a component of other comprehensive income and subsequently reclassified into earnings in the period that the forecasted transaction affects earnings, and the ineffective portion of the gain or loss from the derivative instrument is recognized immediately in earnings.

Fair Value

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

Inventories

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

Property, Plant and Equipment

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

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

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

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.

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

Impairment Assessment. The Corporation tests assets or groups of assets for recoverability 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.

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.

Other. Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any substantial obligation for future performance by the Corporation. Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

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

Asset Retirement Obligations and Environmental Liabilities

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

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

Foreign Currency Translation

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

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. Accounting Changes

Effective January 1, 2018, ExxonMobil adopted the Financial Accounting Standards Board’s Standard, *Revenue from Contracts with Customers (Topic 606)*, as amended. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry and transaction specific requirements, and expands disclosure requirements. The standard was adopted using the Modified Retrospective method, under which prior year results are not restated, but supplemental information is provided for any material impacts of the standard on 2018 results. The adoption of the standard did not have a material impact on any of the lines reported in the Corporation’s financial statements. The cumulative effect of adoption of the standard was de minimis. The Corporation did not elect any practical expedients that require disclosure.

Effective January 1, 2018, ExxonMobil adopted the Financial Accounting Standards Board’s Update, *Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard requires investments in equity securities other than consolidated subsidiaries and equity method investments to be measured at fair value with changes in the fair value recognized through net income. The Corporation elected a modified approach for equity securities that do not have a readily determinable fair value. This modified approach measures investments at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or a similar investment of the same issuer. The cumulative effect adjustment related to the adoption of this standard increased opening 2018 retained earnings $47 million.

Effective January 1, 2018, ExxonMobil adopted the Financial Accounting Standards Board’s Update, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The update requires separate presentation of the service cost component from other components of net benefit costs. The other components are reported in a new line on the Corporation’s Statement of Income, “Non-service pension and postretirement benefit expense”. The Corporation elected to use the practical expedient which uses the amounts disclosed in the pension and other postretirement benefit plan note for the prior comparative periods as the estimation basis for applying the retrospective presentation requirements, as it is impracticable to determine the amounts capitalized in those periods. Beginning in 2018, the other components of net benefit costs are included in the Corporate and financing segment. The estimated after-tax impact from the change in segmentation is an increase in Corporate and financing expenses of about $450 million for 2018. The increase in the Corporate and financing expenses is offset by lower expenses across the operating segments. Additionally, only the service cost component of net benefit costs is eligible for capitalization in situations where it is otherwise appropriate to capitalize employee costs in connection with the construction or production of an asset.

The impact of the retrospective presentation change on ExxonMobil's Consolidated Statement of Income for 2017 and 2016 is shown below.

	2017			2016		
	As Reported	Change	As Adjusted	As Reported	Change	As Adjusted
	(millions of dollars)					
Production and manufacturing expenses	34,128	(1,438)	32,690	31,927	(1,479)	30,448
Selling, general and administrative expenses	10,956	(307)	10,649	10,799	(356)	10,443
Non-service pension and postretirement benefit expense	-	1,745	1,745	-	1,835	1,835

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.

3. Miscellaneous Financial Information

Research and development expenses totaled $1,116 million in 2018, $1,063 million in 2017, and $1,058 million in 2016.

Net income included before-tax aggregate foreign exchange transaction losses of $138 million in 2018, and gains of $6 million and $29 million in 2017 and 2016, respectively.

In 2018, 2017 and 2016, net income included a gain of $107 million, and losses of $10 million, and $295 million, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $8.2 billion and $10.8 billion at December 31, 2018, and 2017, respectively.

Crude oil, products and merchandise as of year-end 2018 and 2017 consist of the following:

	2018	2017
	(millions of dollars)	
Crude oil	4,783	4,635
Petroleum products	5,666	4,333
Chemical products	3,821	3,283
Gas/other	533	620
Total	14,803	12,871

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	Cumulative Foreign Exchange Translation Adjustment	Post-retirement Benefits Reserves Adjustment	Total
		(millions of dollars)	
Balance as of December 31, 2015	(14,170)	(9,341)	(23,511)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(331)	552	221
Amounts reclassified from accumulated other comprehensive income	-	1,051	1,051
Total change in accumulated other comprehensive income	(331)	1,603	1,272
Balance as of December 31, 2016	(14,501)	(7,738)	(22,239)
Current period change excluding amounts reclassified from accumulated other comprehensive income	4,879	(170)	4,709
Amounts reclassified from accumulated other comprehensive income	140	1,128	1,268
Total change in accumulated other comprehensive income	5,019	958	5,977
Balance as of December 31, 2017	(9,482)	(6,780)	(16,262)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(4,595)	201	(4,394)
Amounts reclassified from accumulated other comprehensive income	196	896	1,092
Total change in accumulated other comprehensive income	(4,399)	1,097	(3,302)
Balance as of December 31, 2018	(13,881)	(5,683)	(19,564)

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)	2018	2017	2016
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	(196)	(234)	-
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs (Statement of Income line: Non-service pension and postretirement benefit expense)	(1,208)	(1,656)	(1,531)

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	2018	2017	2016
		(millions of dollars)	
Foreign exchange translation adjustment	32	67	43
Postretirement benefits reserves adjustment (excluding amortization)	(193)	201	(247)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(277)	(491)	(445)
Total	(438)	(223)	(649)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. Cash Flow Information

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

For 2018, the "Net (gain) on asset sales" on the Consolidated Statement of Cash Flows includes before-tax amounts from the sale of service stations in Germany, the divestment of the Augusta refinery in Italy, and the sale of an undeveloped Upstream property in Australia. For 2017, the number includes before-tax amounts from the sale of service stations in multiple countries, Upstream asset transactions in the U.S., and the sale of ExxonMobil's operated Upstream business in Norway. For 2016, the number includes before-tax amounts from the sale of service stations in Canada, the sale of Upstream properties in the U.S., and the sale of aviation fueling operations across multiple countries. These net gains are reported in "Other income" on the Consolidated Statement of Income.

In 2018, the "Additions/(reductions) in commercial paper, and debt with three months or less maturity" on the Consolidated Statement of Cash Flows includes a net $275 million addition of commercial paper with maturity over three months. The gross amount issued was $4.0 billion, while the gross amount repaid was $3.8 billion. In 2017, the number includes a net $121 million repayment of commercial paper with maturity over three months. The gross amount issued was $3.6 billion, while the gross amount repaid was $3.7 billion. In 2016, the number includes a net $608 million addition of commercial paper with maturity over three months. The gross amount issued was $3.9 billion, while the gross amount repaid was $3.3 billion.

In 2017, the Corporation completed the acquisitions of InterOil Corporation, mostly unproved properties in Papua New Guinea, for $2.7 billion and of companies that own mostly unproved oil and gas properties in the Permian Basin and other assets for $6.2 billion. These transactions included a significant noncash component associated with the issuance of a total of 96 million shares of Exxon Mobil Corporation common stock in acquisition consideration, having a total acquisition date value of $7.8 billion.

	2018	2017	2016
		(millions of dollars)	
Cash payments for interest	955	1,132	818
Cash payments for income taxes	9,294	7,510	4,214

6. Additional Working Capital Information

	Dec. 31 2018	Dec. 31 2017
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $61 million and $72 million	19,638	21,274
Other, less reserves of $339 million and $539 million	5,063	4,323
Total	24,701	25,597
Notes and loans payable		
Bank loans	325	115
Commercial paper	12,863	13,049
Long-term debt due within one year	4,070	4,766
Total	17,258	17,930
Accounts payable and accrued liabilities		
Trade payables	21,063	21,701
Payables to equity companies	6,863	5,453
Accrued taxes other than income taxes	3,280	3,311
Other	6,062	6,331
Total	37,268	36,796

The Corporation has short-term committed lines of credit of $5.3 billion which were unused as of December 31, 2018. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 2.4 percent and 1.3 percent at December 31, 2018, and 2017, respectively.

7. Equity Company Information

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

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 14 percent, 15 percent and 14 percent in the years 2018, 2017 and 2016, respectively.

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

	2018		2017		2016	
Equity Company Financial Summary	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**	**Total**	**ExxonMobil Share**
			(millions of dollars)			
Total revenues	112,938	34,539	94,791	29,340	80,247	24,668
Income before income taxes	37,203	10,482	29,748	8,498	22,269	6,509
Income taxes	11,568	3,151	8,421	2,236	6,334	1,701
Income from equity affiliates	25,635	7,331	21,327	6,262	15,935	4,808
Current assets	38,670	13,394	35,367	12,050	34,412	11,392
Long-term assets	128,830	35,970	122,221	34,931	109,646	32,357
Total assets	167,500	49,364	157,588	46,981	144,058	43,749
Current liabilities	27,324	7,606	21,725	6,348	20,507	5,765
Long-term liabilities	56,913	17,109	59,736	17,056	62,110	17,288
Net assets	83,263	24,649	76,127	23,577	61,441	20,696

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A list of significant equity companies as of December 31, 2018, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	
Aera Energy LLC	48
Barzan Gas Company Limited	7
BEB Erdgas und Erdoel GmbH & Co. KG	50
Cameroon Oil Transportation Company S.A.	41
Caspian Pipeline Consortium - Kazakhstan	8
Cross Timbers Energy, LLC	50
Golden Pass LNG Terminal LLC	18
Marine Well Containment Company LLC	10
Mozambique Rovuma Venture, S.p.A.	36
Nederlandse Aardolie Maatschappij B.V.	50
Qatar Liquefied Gas Company Limited	10
Qatar Liquefied Gas Company Limited (2)	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited (II)	31
Ras Laffan Liquefied Natural Gas Company Limited (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	71
Downstream	
Fujian Refining & Petrochemical Co. Ltd.	25
Permian Express Partners LLC	12
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Gulf Coast Growth Ventures LLC	50
Infineum Italia s.r.l.	50
Infineum Singapore Pte. Ltd.	50
Infineum USA L.P.	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2018	Dec. 31, 2017
	(millions of dollars)	
Equity method company investments and advances		
Investments	26,382	24,354
Advances	8,608	9,112
Total equity method company investments and advances	34,990	33,466
Equity securities carried at fair value and other investments at adjusted cost basis *(1)*	210	174
Long-term receivables and miscellaneous, net of reserves of $ 5,471 million and $5,432 million	5,590	5,520
Total	40,790	39,160

(1) Effective January 1, 2018, ExxonMobil adopted the Financial Accounting Standards Board's Update, Financial Instruments - Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities. The portion of unrealized gains and losses recognized during the reporting period on equity securities still held at December 31, 2018, and the carrying value of equity securities without readily determinable fair values at December 31, 2018, were not significant to the Corporation.

9. Property, Plant and Equipment and Asset Retirement Obligations

	December 31, 2018		December 31, 2017	
Property, Plant and Equipment	Cost	Net	Cost	Net
	(millions of dollars)			
Upstream	372,791	194,662	371,904	200,291
Downstream	48,241	21,448	50,343	21,732
Chemical	39,008	20,551	37,966	20,117
Other	17,150	10,440	16,972	10,490
Total	477,190	247,101	477,185	252,630

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 before-tax charges of $0.7 billion to reduce the carrying value of those assets to fair value. In 2017 and 2016, the Corporation recognized before-tax impairment charges of $2.0 billion and $3.6 billion, respectively.

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, a range of discount rates 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.

Accumulated depreciation and depletion totaled $230,089 million at the end of 2018 and $224,555 million at the end of 2017. Interest capitalized in 2018, 2017 and 2016 was $652 million, $749 million and $708 million, respectively.

Asset Retirement Obligations

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

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

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

	2018	2017
	(millions of dollars)	
Beginning balance	12,705	13,243
Accretion expense and other provisions	681	780
Reduction due to property sales	(333)	(906)
Payments made	(600)	(730)
Liabilities incurred	46	128
Foreign currency translation	(481)	611
Revisions	85	(421)
Ending balance	12,103	12,705

The long-term Asset Retirement Obligations were $11,185 million and $11,928 million at December 31, 2018, and 2017, respectively, and are included in Other long-term obligations.

10. Accounting for Suspended Exploratory Well Costs

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

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

Change in capitalized suspended exploratory well costs:

	2018	2017	2016
		(millions of dollars)	
Balance beginning at January 1	3,700	4,477	4,372
Additions pending the determination of proved reserves	564	906	180
Charged to expense	(7)	(1,205)	(111)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(48)	(497)	-
Divestments/Other	(49)	19	36
Ending balance at December 31	4,160	3,700	4,477
Ending balance attributed to equity companies included above	306	306	707

Period end capitalized suspended exploratory well costs:

	2018	2017	2016
		(millions of dollars)	
Capitalized for a period of one year or less	564	906	180
Capitalized for a period of between one and five years	2,028	1,345	2,981
Capitalized for a period of between five and ten years	1,150	1,064	911
Capitalized for a period of greater than ten years	418	385	405
Capitalized for a period greater than one year - subtotal	3,596	2,794	4,297
Total	4,160	3,700	4,477

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a breakdown of the number of projects with only exploratory well costs capitalized for a period of one year or less and those that have had exploratory well costs capitalized for a period of greater than one year.

	2018	2017	2016
Number of projects that only have exploratory well costs capitalized for a period of one year or less	6	11	2
Number of projects that have exploratory well costs capitalized for a period of greater than one year	52	46	58
Total	58	57	60

Of the 52 projects that have exploratory well costs capitalized for a period greater than one year as of December 31, 2018, 12 projects have drilling in the preceding year or exploratory activity planned in the next two years, while the remaining 40 projects are those with completed exploratory activity progressing toward development.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The table below provides additional detail for those 40 projects, which total $2,543 million.

Country/Project	Dec. 31, 2018	Years Wells Drilled / Acquired	Comment
(millions of dollars)			
Angola			
- AB32 Central NE Hub	69	2006 - 2014	Evaluating development plan for tieback to existing production facilities.
- Kaombo Split Hub Phase 2	20	2005 - 2006	Evaluating development plan to tie into planned production facilities.
Argentina			
- La Invernada	72	2014	Evaluating development plan to tie into planned infrastructure.
Australia			
- East Pilchard	7	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/ planned infrastructure.
- Gorgon Area Ullage	318	1994 - 2015	Evaluating development plans to tie into existing LNG facilities.
- SE Longtom	11	2010	Gas field near Tuna development, awaiting capacity in existing/ planned infrastructure.
- SE Remora	33	2010	Gas field near Marlin development, awaiting capacity in existing/ planned infrastructure.
Guyana			
- Liza Phase 2	37	2017	Continuing development plan discussions with the government.
Iraq			
- Kurdistan Pirmam	109	2015	Evaluating commercialization alternatives, while waiting for government approval to enter Gas Holding Period.
Kazakhstan			
- Kairan	53	2004 - 2007	Evaluating commercialization and field development alternatives, while continuing discussions with the government regarding the development plan.
- Kalamkas	18	2006 - 2009	Evaluating/progressing development alternatives, while continuing discussions with the government regarding development plan.
Mozambique			
- Rovuma LNG Future Non-Straddling Train	120	2017	Evaluating/progressing development plan to tie into planned LNG facilities.
- Rovuma LNG Phase 1	150	2017	Progressing development plan to tie into planned LNG facilities.
- Rovuma LNG Unitized Trains	35	2017	Evaluating/progressing development plan to tie into planned LNG facilities.
Nigeria			

- Bolia	15	2002 - 2006	Evaluating development plan, while continuing discussions with the government regarding regional hub strategy.
- Bonga North	34	2004 - 2009	Evaluating/progressing development plan for tieback to existing/ planned infrastructure.
- Bosi	79	2002 - 2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Bosi Central	16	2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Erha Northeast	26	2008	Evaluating development plan for tieback to existing production facilities.
- OML 138 Ukot SS	13	2015	Evaluating development plan for tieback to existing production facilities.
- OML 138 Ukot SW	41	2014	Evaluating development plan for tieback to existing production facilities.
- Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
- Satellite Field Development Phase 2	12	2013	Evaluating development plan to tie into planned production facilities.
- Other (4 projects)	10	2001 - 2002	Evaluating and pursuing development of several additional discoveries.

Country/Project	Dec. 31, 2018	Years Wells Drilled / Acquired	Comment
	(millions of dollars)		
Norway			
- Gamma	13	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- Lavrans	15	1995 - 1999	Evaluating development plan, awaiting capacity in existing Kristin production facility.
- Other (6 projects)	23	2008 - 2014	Evaluating development plans, including potential for tieback to existing production facilities.
Papua New Guinea			
- Juha	28	2007	Progressing development plans to tie into existing LNG facilities.
- Papua LNG	246	2017	Evaluating/progressing development plans.
Republic of Congo			
- Mer Tres Profonde Sud	56	2000 - 2007	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
Romania			
- Neptun Deep	536	2012 - 2016	Continuing discussions with the government regarding development plan.
Vietnam			
- Blue Whale	296	2011 - 2015	Evaluating/progressing development plans.
Total 2018 (40 projects)	2,543		

11. Leased Facilities

At December 31, 2018, the Corporation and its consolidated subsidiaries held noncancelable operating leases and charters covering drilling equipment, tankers and other assets with minimum undiscounted lease commitments totaling $6,112 million as indicated in the table. Estimated related sublease rental income from noncancelable subleases totals $22 million.

	Lease Payments Under Minimum Commitments		
	Drilling Rigs and Related Equipment	Other	Total
	(millions of dollars)		
2019	222	934	1,156
2020	166	819	985
2021	107	658	765
2022	43	506	549
2023	32	422	454
2024 and beyond	53	2,150	2,203
Total	623	5,489	6,112

Net rental cost under both cancelable and noncancelable operating leases incurred during 2018, 2017 and 2016 were as follows:

	2018	2017	2016
		(millions of dollars)	
Rental cost			
Drilling rigs and related equipment	723	792	1,274
Other (net of sublease rental income)	1,992	1,826	1,817
Total	2,715	2,618	3,091

12. Earnings Per Share

Earnings per common share	**2018**	**2017**	**2016**
Net income attributable to ExxonMobil *(millions of dollars)*	20,840	19,710	7,840
Weighted average number of common shares outstanding *(millions of shares)*	4,270	4,256	4,177
Earnings per common share *(dollars) (1)*	4.88	4.63	1.88
Dividends paid per common share *(dollars)*	3.23	3.06	2.98

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

13. Financial Instruments and Derivatives

Financial Instruments. The estimated fair value of financial instruments at December 31, 2018, and the related hierarchy level for the fair value measurement is as follows:

	At December 31, 2018 *(millions of dollars)*							
	Fair Value							
	Level 1	Level 2	Level 3	Total Gross Assets & Liabilities	Effect of Counterparty Netting	Effect of Collateral Netting	Difference in Carrying Value and Fair Value	Net Carrying Value Presented on the Balance Sheet
Assets								
Derivative assets *(1)*	297	-	-	297	(151)	(146)	-	-
Advances to/ receivables from equity companies *(2) (7)*	-	2,100	6,293	8,393	-	-	215	8,608
Other long-term financial assets *(3)*	848	-	974	1,822	-	-	112	1,934
Liabilities								
Derivative liabilities *(4)*	151	-	-	151	(151)	-	-	-
Long-term debt *(5)*	19,029	117	4	19,150	-	-	85	19,235
Long-term obligations to equity companies *(7)*	-	-	4,330	4,330	-	-	52	4,382
Other long-term financial liabilities *(6)*	-	-	1,046	1,046	-	-	(3)	1,043

(1) Included in the Balance Sheet line: Notes and accounts receivable, less estimated doubtful amounts

(2) Included in the Balance Sheet line: Investments, advances and long-term receivables

(3) Included in the Balance Sheet lines: Investments, advances and long-term receivables and Other assets, including intangibles, net

(4) Included in the Balance Sheet line: Accounts payable and accrued liabilities

(5) Excluding capitalized lease obligations

(6) Included in the Balance Sheet line: Other long-term obligations

(7) Advances to/receivables from equity companies and long-term obligations to equity companies are mainly designated as hierarchy level 3 inputs. The fair value is calculated by discounting the remaining obligations by a rate consistent with the credit quality and industry of the equity company.

The estimated fair value of total long-term debt, excluding capitalized lease obligations, was $23.7 billion at December 31, 2017, as compared to recorded book values of $23.1 billion at December 31, 2017.

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in 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. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

The carrying values of derivative instruments on the consolidated balance sheet, at December 31, 2017, were gross assets of $25 million, gross liabilities of ($63) million and collateral receivable of $94 million.

At December 31, 2018, the net notional long/(short) position of derivative instruments was (19) million barrels for crude oil and was (9) million barrels for products.

Realized and unrealized gains/(losses) on derivative instruments that were recognized in the Consolidated Statement of Income are included in the following lines on a before-tax basis:

	2018	2017	2016
	(millions of dollars)		
Sales and other operating revenue	130	6	(12)
Crude oil and product purchases	(120)	(105)	(69)
Total	10	(99)	(81)

14. Long-Term Debt

At December 31, 2018, long-term debt consisted of $19,940 million due in U.S. dollars and $598 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $4,070 million, which matures within one year and is included in current liabilities. The amounts of long-term debt, including capitalized lease obligations, maturing in each of the four years after December 31, 2019, in millions of dollars, are: 2020 – $1,639; 2021 – $2,571; 2022 – $1,841; and 2023 – $1,304. At December 31, 2018, the Corporation's unused long-term credit lines were $0.2 billion.

Summarized long-term debt at year-end 2018 and 2017 are shown in the table below:

	Average Rate *(1)*	**2018**	**2017**
		(millions of dollars)	
Exxon Mobil Corporation			
1.819% notes due 2019		-	1,750
1.708% notes due 2019		-	1,250
Floating-rate notes due 2019 *(Issued 2014)*		-	500
Floating-rate notes due 2019 *(Issued 2016)*		-	250
1.912% notes due 2020		1,500	1,500
2.222% notes due 2021		2,500	2,500
2.397% notes due 2022		1,150	1,150
Floating-rate notes due 2022	2.502%	500	500
2.726% notes due 2023		1,250	1,250
3.176% notes due 2024		1,000	1,000
2.709% notes due 2025		1,750	1,750
3.043% notes due 2026		2,500	2,500
3.567% notes due 2045		1,000	1,000
4.114% notes due 2046		2,500	2,500
XTO Energy Inc. *(2)*			
6.100% senior notes due 2036		195	195
6.750% senior notes due 2037		299	302
6.375% senior notes due 2038		230	232
Mobil Corporation			
8.625% debentures due 2021		250	250
Industrial revenue bonds due 2019-2051	1.334%	2,513	2,559
Other U.S. dollar obligations		102	162
Other foreign currency obligations		38	34
Capitalized lease obligations	9.440%	1,303	1,327
Debt issuance costs		(42)	(55)
Total long-term debt		20,538	24,406

(1) Average effective interest rate for debt and average imputed interest rate for capitalized leases at December 31, 2018.

(2) Includes premiums of $97 million in 2018 and $102 million in 2017.

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of awards. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2018, remaining shares available for award under the 2003 Incentive Program were 82 million.

Restricted Stock and Restricted Stock Units. Awards totaling 8,771 thousand, 8,916 thousand, and 9,583 thousand of restricted (nonvested) common stock units were granted in 2018, 2017 and 2016, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

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

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2018.

	2018	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	41,078	86.34
2017 award issued in 2018	8,910	81.89
Vested	(9,347)	81.14
Forfeited	(260)	85.72
Issued and outstanding at December 31	40,381	86.56

Value of restricted stock units	**2018**	**2017**	**2016**
Grant price *(dollars)*	77.66	81.89	87.70
Value at date of grant:		*(millions of dollars)*	
Units settled in stock	620	667	771
Units settled in cash	61	63	69
Total value	681	730	840

As of December 31, 2018, there was $1,899 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.4 years. The compensation cost charged against income for the restricted stock and restricted stock units was $774 million, $856 million and $880 million for 2018, 2017 and 2016, respectively. The income tax benefit recognized in income related to this compensation expense was $42 million, $78 million and $80 million for the same periods, respectively.

The fair value of shares and units vested in 2018, 2017 and 2016 was $722 million, $826 million and $851 million, respectively. Cash payments of $61 million, $64 million and $67 million for vested restricted stock units settled in cash were made in 2018, 2017 and 2016, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

16. Litigation and Other Contingencies

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

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2018, for guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure.

	December 31, 2018		
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	537	71	608
Other	850	4,380	5,230
Total	1,387	4,451	5,838

(1) ExxonMobil share.

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

In accordance with a Venezuelan nationalization decree issued in February 2007, a subsidiary of the Venezuelan National Oil Company (PdVSA) assumed the operatorship of the Cerro Negro Heavy Oil Project. The decree also required conversion of the Cerro Negro Project into a "mixed enterprise" and an increase in PdVSA's or one of its affiliate's ownership interest in the Project. ExxonMobil refused to accede to the terms proffered by the government, and on June 27, 2007, the government expropriated ExxonMobil's 41.67 percent interest in the Cerro Negro Project.

ExxonMobil collected awards of $908 million in an arbitration against PdVSA under the rules of the International Chamber of Commerce in respect of an indemnity related to the Cerro Negro Project and $260 million in an arbitration for compensation due for the La Ceiba Project and for export curtailments at the Cerro Negro Project under rules of International Centre for Settlement of Investment Disputes (ICSID). An ICSID arbitration award relating to the Cerro Negro Project's expropriation ($1.4 billion) was annulled based on a determination that a prior Tribunal failed to adequately explain why the cap on damages in the indemnity owed by PdVSA did not affect or limit the amount owed for the expropriation of the Cerro Negro Project. ExxonMobil filed a new claim seeking to restore the original award of damages for the Cerro Negro Project with ICSID on September 26, 2018.

The net impact of this matter on the Corporation's consolidated financial results cannot be reasonably estimated. Regardless, the Corporation does not expect the resolution to have a material effect upon the Corporation's operations or financial condition.

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

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2018	2017	2018	2017	2018	2017
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	4.40	3.80	3.00	2.80	4.40	3.80
Long-term rate of compensation increase	5.75	5.75	4.30	4.30	5.75	5.75
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	19,310	19,960	27,963	25,196	8,100	7,800
Service cost	819	784	608	596	152	129
Interest cost	721	798	754	772	301	317
Actuarial loss/(gain)	(957)	733	(1,034)	250	(630)	231
Benefits paid *(1) (2)*	(1,715)	(2,964)	(1,284)	(1,291)	(528)	(543)
Foreign exchange rate changes	-	-	(1,664)	2,484	(49)	40
Amendments, divestments and other	(4)	(1)	35	(44)	125	126
Benefit obligation at December 31	18,174	19,310	25,378	27,963	7,471	8,100
Accumulated benefit obligation at December 31	14,683	15,557	23,350	25,557	-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2018 and 2017, other postretirement benefits paid are net of $13 million and $16 million of Medicare subsidy receipts, respectively.

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the effective discount rate determined by use of a yield curve based on high-quality, noncallable bonds applied to the estimated cash outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using a spot yield curve of high-quality, local-currency-denominated bonds at an average maturity approximating that of the liabilities.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.5 percent in 2020 and subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $74 million and the postretirement benefit obligation by $776 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $56 million and the postretirement benefit obligation by $620 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2018	2017	2018	2017	2018	2017
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	12,782	12,793	21,461	19,043	427	411
Actual return on plan assets	(710)	1,831	(15)	1,442	(13)	40
Foreign exchange rate changes	-	-	(1,320)	1,776	-	-
Company contribution	491	619	438	440	30	34
Benefits paid *(1)*	(1,429)	(2,461)	(903)	(902)	(58)	(58)
Other	-	-	(175)	(338)	-	-

Fair value at December 31	11,134	12,782	19,486	21,461	386	427

(1) Benefit payments for funded plans.

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2018	2017	2018	2017
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(4,604)	(3,957)	439	413
Unfunded plans	(2,436)	(2,571)	(6,331)	(6,915)
Total	(7,040)	(6,528)	(5,892)	(6,502)

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2018	2017	2018	2017	2018	2017
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(7,040)	(6,528)	(5,892)	(6,502)	(7,085)	(7,673)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	-	-	1,174	1,403	-	-
Current liabilities	(243)	(276)	(314)	(338)	(362)	(360)
Postretirement benefits reserves	(6,797)	(6,252)	(6,752)	(7,567)	(6,723)	(7,313)
Total recorded	(7,040)	(6,528)	(5,892)	(6,502)	(7,085)	(7,673)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	3,831	3,982	4,713	5,586	877	1,595
Prior service cost	6	11	(93)	(143)	(357)	(397)
Total recorded in accumulated other comprehensive income	3,837	3,993	4,620	5,443	520	1,198

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

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

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31					(percent)				
Discount rate	3.80	4.25	4.25	2.80	3.00	3.60	3.80	4.25	4.25
Long-term rate of return on funded assets	6.00	6.50	6.50	4.70	5.20	5.25	6.00	6.50	6.50
Long-term rate of compensation increase	5.75	5.75	5.75	4.30	4.00	4.80	5.75	5.75	5.75
Components of net periodic benefit cost					(millions of dollars)				
Service cost	819	784	810	608	596	585	152	129	153
Interest cost	721	798	793	754	772	844	301	317	344
Expected return on plan assets	(727)	(775)	(726)	(951)	(1,000)	(927)	(23)	(24)	(25)
Amortization of actuarial loss/(gain)	362	438	492	409	476	536	116	96	153
Amortization of prior service cost	5	5	6	46	47	54	(40)	(33)	(30)
Net pension enhancement and curtailment/settlement cost	268	609	319	44	19	2	-	-	-
Net periodic benefit cost	1,448	1,859	1,694	910	910	1,094	506	485	595
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	479	(324)	27	(66)	(191)	(156)	(594)	215	(555)
Amortization of actuarial (loss)/gain	(630)	(1,047)	(811)	(453)	(495)	(538)	(116)	(96)	(153)
Prior service cost/(credit)	-	-	-	98	111	32	-	-	-
Amortization of prior service (cost)/credit	(5)	(5)	(6)	(46)	(47)	(54)	40	33	30
Foreign exchange rate changes	-	-	-	(356)	559	(108)	(8)	8	5
Total recorded in other comprehensive income	(156)	(1,376)	(790)	(823)	(63)	(824)	(678)	160	(673)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	1,292	483	904	87	847	270	(172)	645	(78)

Costs for defined contribution plans were $391 million, $384 million and $399 million in 2018, 2017 and 2016, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2018	2017	2016
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	156	1,376	790
Non-U.S. pension	823	63	824
Other postretirement benefits	678	(160)	673
Total (charge)/credit to other comprehensive income, before tax	1,657	1,279	2,287
(Charge)/credit to income tax (see Note 4)	(470)	(290)	(692)
(Charge)/credit to investment in equity companies	24	(43)	(16)
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	1,211	946	1,579
Charge/(credit) to equity of noncontrolling interests	(114)	12	24
(Charge)/credit to other comprehensive income attributable to ExxonMobil	1,097	958	1,603

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

Studies are periodically conducted to establish the preferred target asset allocation percentages. The target asset allocation for the U.S. benefit plans and the major non-U.S. plans is 30 percent equity securities and 70 percent debt securities. The equity targets for the U.S. and certain non-U.S. plans include a small allocation to private equity partnerships that primarily focus on early-stage venture capital of 5 percent and 3 percent, respectively.

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

The 2018 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2018, Using:					Fair Value Measurement at December 31, 2018, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
					(millions of dollars)					
Asset category:										
Equity securities										
U.S.	-	-	-	1,397	1,397	-	-	-	2,648	2,648
Non-U.S.	-	-	-	1,218	1,218	57 *(2)*	-	-	2,436	2,493
Private equity	-	-	-	516	516	-	-	-	513	513
Debt securities										
Corporate	-	4,795 *(3)*	-	1	4,796	-	102 *(3)*	-	3,713	3,815
Government	-	3,085 *(3)*	-	2	3,087	243 *(4)*	97 *(3)*	-	9,326	9,666
Asset-backed	-	-	-	1	1	-	28 *(3)*	-	218	246
Cash	-	-	-	111	111	27	3 *(5)*	-	54	84
Total at fair value	-	7,880	-	3,246	11,126	327	230	-	18,908	19,465
Insurance contracts at contract value					8					21
Total plan assets					11,134					19,486

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

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2018, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
			(millions of dollars)		
Asset category:					
Equity securities					
U.S.	-	-	-	64	64
Non-U.S.	-	-	-	41	41
Debt securities					
Corporate	-	88 *(2)*	-	-	88
Government	-	189 *(2)*	-	-	189
Asset-backed	-	-	-	-	-
Cash	-	-	-	4	4
Total at fair value	-	277	-	109	386

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

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

The 2017 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2017, Using:					Fair Value Measurement at December 31, 2017, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
					(millions of dollars)					
Asset category:										
Equity securities										
U.S.	-	-	-	1,665	1,665	-	-	-	2,967	2,967
Non-U.S.	-	-	-	1,570	1,570	111 *(2)*	-	-	2,903	3,014
Private equity	-	-	-	532	532	-	-	-	522	522
Debt securities										
Corporate	-	5,260 *(3)*	-	1	5,261	-	131 *(3)*	-	5,215	5,346
Government	-	3,604 *(3)*	-	2	3,606	237 *(4)*	32 *(3)*	-	9,056	9,325
Asset-backed	-	-	-	1	1	-	34 *(3)*	-	72	106
Cash	-	-	-	138	138	54	2 *(5)*	-	102	158
Total at fair value	-	8,864	-	3,909	12,773	402	199	-	20,837	21,438
Insurance contracts										
at contract value					9					23
Total plan assets					12,782					21,461

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

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2017, Using:				
	Level 1	Level 2	Level 3	Net Asset Value (1)	Total
	(millions of dollars)				
Asset category:					
Equity securities					
U.S.	-	-	-	73	73
Non-U.S.	-	-	-	55	55
Debt securities					
Corporate	-	99 (2)	-	-	99
Government	-	197 (2)	-	-	197
Asset-backed	-	1 (2)	-	-	1
Cash	-	-	-	2	2
Total at fair value	-	297	-	130	427

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

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

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2018	2017	2018	2017
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	15,738	16,739	4,037	3,384
Accumulated benefit obligation	13,208	14,022	3,671	3,264
Fair value of plan assets	11,134	12,782	3,499	3,219
For unfunded pension plans:				
Projected benefit obligation	2,436	2,571	6,331	6,915
Accumulated benefit obligation	1,475	1,535	5,670	6,208

	Pension Benefits		Other Postretirement Benefits
	U.S.	Non-U.S.	
	(millions of dollars)		
Estimated 2019 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	510	357	59
Prior service cost *(2)*	5	48	(42)

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

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

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2019	1,020	680	-	-
Benefit payments expected in:				
2019	1,353	1,113	454	19
2020	1,312	1,111	458	20
2021	1,310	1,127	461	20
2022	1,302	1,138	463	22
2023	1,307	1,156	456	23
2024 - 2028	6,393	5,806	2,259	126

18. Disclosures about Segments and Related Information

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

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

Earnings after income tax include transfers at estimated market prices.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense of $84 million in 2018, $136 million in 2017 and $63 million in 2016.

	Upstream		Downstream		Chemical		Corporate and Financing	Corporate Total
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.		
				(millions of dollars)				
As of December 31, 2018								
Earnings after income tax *(1)*	1,739	12,340	2,962	3,048	1,642	1,709	(2,600)	20,840
Earnings of equity companies included above	608	5,816	156	(6)	48	1,113	(380)	7,355
Sales and other operating revenue	10,359	15,158	74,327	147,007	12,239	20,204	38	279,332
Intersegment revenue	8,683	29,659	21,954	29,888	9,044	7,217	205	-
Depreciation and depletion expense	6,024	9,257	684	890	405	606	879	18,745
Interest revenue	-	-	-	-	-	-	64	64
Interest expense	77	31	2	12	-	1	643	766
Income tax expense (benefit)	104	8,149	946	1,008	566	245	(1,486)	9,532
Additions to property, plant and equipment	7,119	7,974	1,152	1,595	1,146	348	717	20,051
Investments in equity companies	4,566	16,337	293	1,162	870	3,431	(277)	26,382
Total assets	90,310	148,914	17,898	34,024	14,904	21,131	19,015	346,196
As of December 31, 2017								
Earnings after income tax	6,622	6,733	1,948	3,649	2,190	2,328	(3,760)	19,710
Earnings of equity companies included above	216	3,618	118	490	90	1,217	(369)	5,380
Sales and other operating revenue	9,349	14,508	61,695	122,881	11,035	17,659	35	237,162
Intersegment revenue	5,729	22,935	14,857	22,263	7,270	5,550	208	-
Depreciation and depletion expense	6,963	9,741	658	883	299	504	845	19,893
Interest revenue	-	-	-	-	-	-	36	36
Interest expense	87	29	1	6	-	-	478	601
Income tax expense (benefit)	(8,552)	5,463	(61)	934	362	664	16	(1,174)
Effect of U.S. tax reform - noncash	*(7,602)*	*480*	*(618)*	*-*	*(335)*	*-*	*2,133*	*(5,942)*
Additions to property, plant and equipment	9,761	8,617	769	1,551	1,330	2,019	854	24,901
Investments in equity companies	4,680	14,494	276	1,462	341	3,387	(286)	24,354
Total assets	89,048	155,822	18,172	34,294	13,363	21,133	16,859	348,691
As of December 31, 2016								
Earnings after income tax	(4,151)	4,347	1,094	3,107	1,876	2,739	(1,172)	7,840
Earnings of equity companies included above	53	3,359	58	404	111	1,188	(367)	4,806
Sales and other operating revenue	7,552	12,278	52,630	102,756	9,944	15,447	21	200,628
Intersegment revenue	3,827	18,099	11,796	18,775	6,404	4,211	236	-
Depreciation and depletion expense	9,626	9,550	628	889	275	477	863	22,308
Interest revenue	-	-	-	-	-	-	30	30
Interest expense	17	29	1	8	-	-	398	453
Income tax expense (benefit)	(2,600)	1,818	396	951	693	609	(2,273)	(406)
Additions to property, plant and equipment	3,144	7,878	791	1,525	1,463	482	817	16,100
Investments in equity companies	4,917	11,364	111	1,255	158	3,247	(242)	20,810
Total assets	86,146	153,183	16,201	29,208	11,600	18,453	15,523	330,314

(1) See Note 2 for additional details regarding the change in segmentation of Non-service pension and postretirement benefit expense.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Geographic

Sales and other operating revenue	**2018**	**2017**	**2016**
		(millions of dollars)	
United States	96,930	82,079	70,126
Non-U.S.	182,402	155,083	130,502
Total	279,332	237,162	200,628
Significant non-U.S. revenue sources include: *(1)*			
Canada	22,672	20,116	17,682
United Kingdom	18,702	16,611	15,452
Belgium	15,664	13,633	10,834
Singapore	13,689	11,589	9,919
France	13,637	11,235	9,487
Italy	13,396	11,476	9,715
Germany	9,426	8,484	7,899

(1) Revenue is determined by primary country of operations. Excludes certain sales and other operating revenues in Non-U.S. operations where attribution to a specific country is not practicable.

Long-lived assets	**2018**	**2017**	**2016**
		(millions of dollars)	
United States	108,147	105,101	101,194
Non-U.S.	138,954	147,529	143,030
Total	247,101	252,630	244,224
Significant non-U.S. long-lived assets include:			
Canada	37,433	41,138	40,144
Australia	14,548	16,908	16,510
Singapore	11,148	11,292	9,769
Kazakhstan	9,726	10,121	10,325
Nigeria	8,421	9,734	11,314
Papua New Guinea	8,269	8,463	5,719
Angola	7,021	7,689	8,413
Russia	5,456	5,702	4,828

19. Income and Other Taxes

	2018			2017			2016		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
					(millions of dollars)				
Income tax expense									
Federal and non-U.S.									
Current	459	9,001	9,460	577	6,633	7,210	(214)	4,056	3,842
Deferred - net	518	(614)	(96)	(9,075)	754	(8,321)	(2,801)	(1,422)	(4,223)
U.S. tax on non-U.S. operations	42	-	42	17	-	17	41	-	41
Total federal and non-U.S.	1,019	8,387	9,406	(8,481)	7,387	(1,094)	(2,974)	2,634	(340)
State	126	-	126	(80)	-	(80)	(66)	-	(66)
Total income tax expense	1,145	8,387	9,532	(8,561)	7,387	(1,174)	(3,040)	2,634	(406)
All other taxes and duties									
Other taxes and duties	3,498	29,165	32,663	3,330	26,774	30,104	3,209	25,811	29,020
Included in production and manufacturing expenses	1,245	857	2,102	1,107	747	1,854	1,052	808	1,860
Included in SG&A expenses	153	312	465	147	354	501	133	362	495
Total other taxes and duties	4,896	30,334	35,230	4,584	27,875	32,459	4,394	26,981	31,375
Total	6,041	38,721	44,762	(3,977)	35,262	31,285	1,354	29,615	30,969

The above provisions for deferred income taxes include a net credit of $289 million in 2018 related to changes in tax laws and rates, mainly from a $291 million credit related to U.S. tax reform. For 2017, deferred income tax expense includes a net credit of $5,920 million, reflecting a $5,942 million credit related to U.S. tax reform and $22 million of other changes in tax laws and rates outside of the United States. Deferred income tax expense for 2016 includes net charges of $180 million for the effect of changes in tax laws and rates.

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).

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 21 percent for 2018 and 35 percent for 2017 and 2016 is as follows:

	2018	2017	2016
		(millions of dollars)	
Income before income taxes			
United States	5,200	(754)	(5,832)
Non-U.S.	25,753	19,428	13,801
Total	30,953	18,674	7,969
Theoretical tax	6,500	6,536	2,789
Effect of equity method of accounting	(1,545)	(1,883)	(1,682)
Non-U.S. taxes in excess of/(less than) theoretical U.S. tax *(1)*	4,626	1,848	(582)
Enactment-date effects of U.S. tax reform	(291)	(5,942)	-
Other *(2)*	242	(1,733)	(931)
Total income tax expense	9,532	(1,174)	(406)
Effective tax rate calculation			
Income taxes	9,532	(1,174)	(406)
ExxonMobil share of equity company income taxes	3,142	2,228	1,692
Total income taxes	12,674	1,054	1,286
Net income including noncontrolling interests	21,421	19,848	8,375
Total income before taxes	34,095	20,902	9,661
Effective income tax rate	37%	5%	13%

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

(2) 2017 includes an exploration tax benefit of $708 million. 2016 includes an exploration tax benefit of $198 million and benefits from an adjustment to a prior year tax position of $176 million.

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

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

Tax effects of temporary differences for:	2018	2017
	(millions of dollars)	
Property, plant and equipment	35,745	36,559
Other liabilities	6,516	5,625
Total deferred tax liabilities	42,261	42,184
Pension and other postretirement benefits	(4,115)	(4,338)
Asset retirement obligations	(4,118)	(4,237)
Tax loss carryforwards	(6,321)	(6,767)
Other assets	(5,498)	(5,832)
Total deferred tax assets	(20,052)	(21,174)
Asset valuation allowances	1,826	2,565
Net deferred tax liabilities	24,035	23,575

In 2018, asset valuation allowances of $1,826 million decreased by $739 million, including $234 million related to U.S. tax reform and $333 million related to a reduction in deferred tax assets.

Balance sheet classification	2018	2017
	(millions of dollars)	
Other assets, including intangibles, net	(3,209)	(3,318)
Deferred income tax liabilities	27,244	26,893
Net deferred tax liabilities	24,035	23,575

The Corporation's undistributed earnings from subsidiary companies outside the United States include amounts that have been retained to fund prior and future capital project expenditures. Deferred income taxes have not been recorded for potential future tax obligations, such as foreign withholding tax and state tax, as these undistributed earnings are expected to be indefinitely reinvested for the foreseeable future. As of December 31, 2018, it is not practicable to estimate the unrecognized deferred tax liability. However, unrecognized deferred taxes on remittance of these funds are not expected to be material.

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

Gross unrecognized tax benefits	**2018**	**2017**	**2016**
		(millions of dollars)	
Balance at January 1	8,783	9,468	9,396
Additions based on current year's tax positions	375	522	655
Additions for prior years' tax positions	240	523	534
Reductions for prior years' tax positions	(125)	(865)	(1,019)
Reductions due to lapse of the statute of limitations	(5)	(113)	(7)
Settlements with tax authorities	(68)	(782)	(70)
Foreign exchange effects/other	(26)	30	(21)
Balance at December 31	9,174	8,783	9,468

The gross unrecognized tax benefit balances shown above are predominantly related to tax positions that would reduce the Corporation’s effective tax rate if the positions are favorably resolved. Unfavorable resolution of these tax positions generally would not increase the effective tax rate. The 2018, 2017 and 2016 changes in unrecognized tax benefits did not have a material effect on the Corporation’s net income.

Resolution of these tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control of the Corporation. In the United States, the Corporation has various ongoing U.S. federal income tax positions at issue with the Internal Revenue Service (IRS) for tax years beginning in 2006. The IRS has asserted penalties associated with several of those positions. The Corporation has not recognized the penalties as an expense because the Corporation does not expect the penalties to be sustained under applicable law. The Corporation has filed a refund suit for tax years 2006-2009 in a U.S. federal district court with respect to the positions at issue for those years. Unfavorable resolution of all positions at issue with the IRS would not have a materially adverse effect on the Corporation’s net income or liquidity.

It is reasonably possible that the total amount of unrecognized tax benefits could increase or decrease by 10 percent in the next 12 months with no material impact on the Corporation's net income.

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

Country of Operation	**Open Tax Years**
Abu Dhabi	2018…..
Angola	2017 - 2018
Australia	2008 - 2018
Belgium	2016 - 2018
Canada	2000 - 2018
Equatorial Guinea	2007 - 2018
Indonesia	2007 - 2018
Iraq	2013 - 2018
Malaysia	2009 - 2018
Nigeria	2006 - 2018
Norway	2007 - 2018
Papua New Guinea	2008 - 2018
Russia	2016 - 2018
United Kingdom	2015 - 2018
United States	2006 - 2018

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

The Corporation incurred $3 million, $36 million and $4 million in interest expense on income tax reserves in 2018, 2017 and 2016, respectively. The related interest payable balances were $169 million and $168 million at December 31, 2018, and 2017, respectively.

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $1,484 million in 2018, $1,402 million in 2017 and $719 million in 2016. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2018 - Revenue							
Sales to third parties	5,914	1,491	3,680	1,136	2,431	3,256	17,908
Transfers	5,822	4,633	1,573	8,844	8,461	873	30,206
	11,736	6,124	5,253	9,980	10,892	4,129	48,114
Production costs excluding taxes	3,915	4,211	1,348	2,454	1,501	680	14,109
Exploration expenses	237	434	140	318	209	128	1,466
Depreciation and depletion	5,775	1,803	665	2,788	2,088	809	13,928
Taxes other than income	953	133	128	799	1,155	335	3,503
Related income tax	250	(121)	1,934	1,766	4,008	622	8,459
Results of producing activities for consolidated subsidiaries	606	(336)	1,038	1,855	1,931	1,555	6,649
Equity Companies							
2018 - Revenue							
Sales to third parties	747	-	1,420	-	12,028	-	14,195
Transfers	588	-	8	-	935	-	1,531
	1,335	-	1,428	-	12,963	-	15,726
Production costs excluding taxes	535	-	745	5	409	-	1,694
Exploration expenses	1	-	4	-	5	-	10
Depreciation and depletion	248	-	172	-	462	-	882
Taxes other than income	33	-	61	-	4,104	-	4,198
Related income tax	-	-	271	(1)	2,726	-	2,996
Results of producing activities for equity companies	518	-	175	(4)	5,257	-	5,946
Total results of operations	1,124	(336)	1,213	1,851	7,188	1,555	12,595

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2017 - Revenue							
Sales to third parties	5,223	1,911	3,652	993	2,239	2,244	16,262
Transfers	3,852	3,462	1,631	7,771	6,035	689	23,440
	9,075	5,373	5,283	8,764	8,274	2,933	39,702
Production costs excluding taxes	3,730	3,833	1,576	2,064	1,618	626	13,447
Exploration expenses	162	647	94	311	494	82	1,790
Depreciation and depletion	6,689	2,005	1,055	2,957	1,782	913	15,401
Taxes other than income	684	97	146	559	811	311	2,608
Related income tax	(8,066)	(180)	1,717	1,911	2,148	316	(2,154)
Results of producing activities for consolidated subsidiaries	5,876	(1,029)	695	962	1,421	685	8,610
Equity Companies							
2017 - Revenue							
Sales to third parties	585	-	1,636	-	8,926	-	11,147
Transfers	443	-	10	-	638	-	1,091
	1,028	-	1,646	-	9,564	-	12,238
Production costs excluding taxes	523	-	418	-	336	-	1,277
Exploration expenses	1	-	13	-	878	-	892
Depreciation and depletion	320	-	166	-	477	-	963
Taxes other than income	33	-	679	-	2,997	-	3,709
Related income tax	-	-	130	-	1,924	-	2,054
Results of producing activities for equity companies	151	-	240	-	2,952	-	3,343
Total results of operations	6,027	(1,029)	935	962	4,373	685	11,953
Consolidated Subsidiaries							
2016 - Revenue							
Sales to third parties	4,424	1,511	2,921	705	1,826	1,273	12,660
Transfers	2,323	2,652	1,568	6,498	4,638	578	18,257
	6,747	4,163	4,489	7,203	6,464	1,851	30,917
Production costs excluding taxes	3,590	3,651	1,794	2,216	1,331	531	13,113
Exploration expenses	220	572	94	292	205	84	1,467
Depreciation and depletion	9,334	1,601	1,678	3,573	1,613	532	18,331
Taxes other than income	491	165	139	762	621	209	2,387
Related income tax	(2,543)	(688)	546	(149)	1,767	167	(900)
Results of producing activities for consolidated subsidiaries	(4,345)	(1,138)	238	509	927	328	(3,481)
Equity Companies							
2016 - Revenue							
Sales to third parties	506	-	1,677	-	7,208	-	9,391
Transfers	344	-	9	-	418	-	771
	850	-	1,686	-	7,626	-	10,162
Production costs excluding taxes	527	-	529	-	504	-	1,560
Exploration expenses	-	-	36	-	21	-	57
Depreciation and depletion	301	-	143	-	437	-	881
Taxes other than income	31	-	661	-	2,456	-	3,148

Related income tax	-	-	86	-	1,472	-	1,558
Results of producing activities for equity companies	(9)	-	231	-	2,736	-	2,958
Total results of operations	(4,354)	(1,138)	469	509	3,663	328	(523)

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $13,474 million less at year-end 2018 and $15,292 million less at year-end 2017 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
Consolidated Subsidiaries								
As of December 31, 2018								
Property (acreage) costs	- Proved	17,996	2,482	147	982	2,944	722	25,273
	- Unproved	26,357	6,872	45	155	179	2,692	36,300
Total property costs		44,353	9,354	192	1,137	3,123	3,414	61,573
Producing assets		95,532	45,874	28,564	53,722	39,173	13,587	276,452
Incomplete construction		4,174	2,873	1,475	3,368	4,985	1,525	18,400
Total capitalized costs		144,059	58,101	30,231	58,227	47,281	18,526	356,425
Accumulated depreciation and depletion		62,950	18,994	25,803	40,710	20,206	6,574	175,237
Net capitalized costs for consolidated subsidiaries		81,109	39,107	4,428	17,517	27,075	11,952	181,188
Equity Companies								
As of December 31, 2018								
Property (acreage) costs	- Proved	98	-	4	309	-	-	411
	- Unproved	10	-	-	3,111	-	-	3,121
Total property costs		108	-	4	3,420	-	-	3,532
Producing assets		6,766	-	5,547	-	7,719	-	20,032
Incomplete construction		148	-	12	581	7,044	-	7,785
Total capitalized costs		7,022	-	5,563	4,001	14,763	-	31,349
Accumulated depreciation and depletion		2,968	-	4,653	-	4,843	-	12,464
Net capitalized costs for equity companies		4,054	-	910	4,001	9,920	-	18,885
Consolidated Subsidiaries								
As of December 31, 2017								
Property (acreage) costs	- Proved	17,380	2,560	139	982	2,624	778	24,463
	- Unproved	27,051	5,238	62	196	179	2,701	35,427
Total property costs		44,431	7,798	201	1,178	2,803	3,479	59,890
Producing assets		94,253	48,951	30,908	52,137	37,808	14,564	278,621
Incomplete construction		2,016	1,484	1,173	4,294	5,499	1,440	15,906
Total capitalized costs		140,700	58,233	32,282	57,609	46,110	19,483	354,417
Accumulated depreciation and depletion		61,041	18,780	27,040	37,924	18,354	6,279	169,418
Net capitalized costs for consolidated subsidiaries		79,659	39,453	5,242	19,685	27,756	13,204	184,999
Equity Companies								
As of December 31, 2017								
Property (acreage) costs	- Proved	78	-	4	309	-	-	391
	- Unproved	11	-	-	3,111	59	-	3,181
Total property costs		89	-	4	3,420	59	-	3,572
Producing assets		6,410	-	5,678	-	9,824	-	21,912
Incomplete construction		98	-	45	516	4,611	-	5,270

Total capitalized costs	6,597	-	5,727	3,936	14,494	-	30,754
Accumulated depreciation and depletion	2,722	-	4,625	-	6,519	-	13,866
Net capitalized costs for equity companies	3,875	-	1,102	3,936	7,975	-	16,888

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2018 were $16,328 million, down $3,316 million from 2017, due primarily to lower acquisition costs of unproved properties, partially offset by higher development costs. In 2017 costs were $19,644 million, up $8,269 million from 2016, due primarily to acquisitions of unproved properties, partially offset by lower development costs including lower asset retirement obligation cost estimates mainly in the North Sea. Total equity company costs incurred in 2018 were $3,031 million, down $2,977 million from 2017, due primarily to lower acquisition costs of unproved properties.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		**United States**	**Canada/ Other Americas**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)				
During 2018								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	7	3	-	-	321	-	331
	- Unproved	238	2,109	-	1	-	-	2,348
Exploration costs		235	1,113	147	342	217	174	2,228
Development costs		7,440	1,734	96	791	1,104	256	11,421
Total costs incurred for consolidated subsidiaries		7,920	4,959	243	1,134	1,642	430	16,328
Equity Companies								
Property acquisition costs	- Proved	21	-	-	-	-	-	21
	- Unproved	-	-	-	-	-	-	-
Exploration costs		1	-	4	-	5	-	10
Development costs		442	-	40	66	2,452	-	3,000
Total costs incurred for equity companies		464	-	44	66	2,457	-	3,031
During 2017								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	88	5	-	50	583	-	726
	- Unproved	6,167	1,004	35	70	-	2,601	9,877
Exploration costs		190	702	109	373	224	509	2,107
Development costs		3,752	877	(39)	628	1,450	266	6,934
Total costs incurred for consolidated subsidiaries		10,197	2,588	105	1,121	2,257	3,376	19,644
Equity Companies								
Property acquisition costs	- Proved	-	-	-	309	-	-	309
	- Unproved	-	-	-	3,111	-	-	3,111
Exploration costs		1	-	3	323	90	-	417
Development costs		137	-	41	192	1,801	-	2,171
Total costs incurred for equity companies		138	-	44	3,935	1,891	-	6,008
During 2016								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	1	1	-	-	71	-	73
	- Unproved	170	27	-	-	-	-	197
Exploration costs		145	689	156	321	187	133	1,631
Development costs		3,054	1,396	538	1,866	2,214	406	9,474

Total costs incurred for consolidated subsidiaries		3,370	2,113	694	2,187	2,472	539	11,375
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	-	-	-
Exploration costs		1	-	36	-	32	-	69
Development costs		106	-	88	-	1,143	-	1,337
Total costs incurred for equity companies		107	-	124	-	1,175	-	1,406

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2016, 2017 and 2018.

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

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

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

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

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

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

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The production and reserves reported for these types of arrangements typically vary inversely with oil and natural gas price changes. As oil and natural gas prices increase, the cash flow and value received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2018 that were associated with production sharing contract arrangements was 8 percent of liquids, 10 percent of natural gas and 9 percent on an oil-equivalent basis (natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels).

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

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

The changes between 2018 year-end proved reserves and 2017 year-end proved reserves include upward revisions of 3.4 billion barrels of bitumen at Kearl as a result of improved prices; downward natural gas revisions for the Groningen field in the Netherlands; and extensions/discoveries primarily in the United States. 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. In anticipation of a lower production outlook, the Corporation reduced its estimate of proved reserves by 0.8 billion oil-equivalent barrels for the Groningen gas field.

The changes between 2017 year-end proved reserves and 2016 year-end proved reserves primarily reflect extensions/discoveries in the United States, Guyana, and the United Arab Emirates, as well as purchases in the Permian Basin and offshore Area 4 in Mozambique, along with upward revisions to North America natural gas, liquids in the United Arab Emirates, and bitumen at Kearl and Cold Lake. Downward revisions are reflected in Europe for the Groningen gas field.

The downward revisions in 2016, as the result of very low prices during 2016, included the entire 3.5 billion barrels of bitumen at Kearl. In addition, 0.8 billion barrels of oil equivalent across the remainder of North America no longer qualified as proved reserves at year-end 2016 mainly due to the acceleration of the projected end-of-field-life.

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

	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2016	2,378	260	184	963	2,825	125	6,735	1,078	4,560	581	12,954
Revisions	(307)	3	43	49	73	9	(130)	47	(3,748)	8	(3,823)
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	79	-	-	-	-	-	79	32	-	-	111
Sales	(15)	(5)	(3)	-	-	-	(23)	(5)	-	-	(28)
Extensions/discoveries	173	3	12	-	-	-	188	66	-	-	254
Production	(127)	(20)	(63)	(168)	(140)	(13)	(531)	(64)	(111)	(25)	(731)
December 31, 2016	2,181	241	173	844	2,758	121	6,318	1,154	701	564	8,737
Attributable to noncontrolling interests		*8*						*2*	*213*	*171*	
Proportional interest in proved reserves of equity companies											
January 1, 2016	254	-	25	-	1,077	-	1,356	414	-	-	1,770
Revisions	3	-	(7)	-	191	-	187	(5)	-	-	182
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(21)	-	(1)	-	(85)	-	(107)	(25)	-	-	(132)
December 31, 2016	236	-	17	-	1,183	-	1,436	384	-	-	1,820
Total liquids proved reserves at December 31, 2016	2,417	241	190	844	3,941	121	7,754	1,538	701	564	10,557
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2017	2,181	241	173	844	2,758	121	6,318	1,154	701	564	8,737
Revisions	70	19	43	30	490	2	654	(49)	416	(70)	951
Improved recovery	-	-	-	2	-	-	2	-	6	-	8
Purchases	428	5	-	-	-	-	433	164	-	-	597
Sales	(10)	-	(43)	-	-	-	(53)	(2)	-	-	(55)
Extensions/discoveries	158	161	-	3	384	-	706	58	-	-	764
Production	(132)	(16)	(54)	(150)	(136)	(13)	(501)	(67)	(111)	(21)	(700)
December 31, 2017	2,695	410	119	729	3,496	110	7,559	1,258	1,012	473	10,302
Attributable to noncontrolling interests		*10*						*3*	*288*	*144*	
Proportional interest in proved reserves of equity companies											
January 1, 2017	236	-	17	-	1,183	-	1,436	384	-	-	1,820
Revisions	29	-	(1)	-	-	-	28	4	-	-	32
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	6	-	-	6	-	-	-	6
Sales	-	-	-	-	-	-	-	-	-	-	-

Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(20)	-	(1)	-	(86)	-	(107)	(24)	-	-	(131)
December 31, 2017	245	-	15	6	1,097	-	1,363	364	-	-	1,727
Total liquids proved reserves at December 31, 2017	2,940	410	134	735	4,593	110	8,922	1,622	1,012	473	12,029

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

	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2018	2,695	410	119	729	3,496	110	7,559	1,258	1,012	473	10,302
Revisions	61	28	63	(9)	4	6	153	(16)	3,286	15	3,438
Improved recovery	-	-	23	13	-	-	36	-	-	-	36
Purchases	8	-	-	-	-	-	8	2	-	-	10
Sales	(11)	-	(2)	-	-	-	(13)	(13)	-	-	(26)
Extensions/discoveries	595	113	-	9	3	-	720	238	-	-	958
Production	(144)	(22)	(37)	(138)	(146)	(11)	(498)	(65)	(113)	(22)	(698)
December 31, 2018	3,204	529	166	604	3,357	105	7,965	1,404	4,185	466	14,020
Attributable to noncontrolling interests		*44*						*4*	*962*	*142*	
Proportional interest in proved reserves of equity companies											
January 1, 2018	245	-	15	6	1,097	-	1,363	364	-	-	1,727
Revisions	28	-	1	-	6	-	35	1	-	-	36
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	1	-	-	-	-	-	1	-	-	-	1
Production	(20)	-	(1)	-	(83)	-	(104)	(23)	-	-	(127)
December 31, 2018	254	-	15	6	1,020	-	1,295	342	-	-	1,637
Total liquids proved reserves at December 31, 2018	3,458	529	181	610	4,377	105	9,260	1,746	4,185	466	15,657

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ Other Americas	Canada/ Other Americas	Total
					(millions of barrels)					
Proved developed reserves, as of December 31, 2016										
Consolidated subsidiaries	1,317	87	175	836	1,858	105	4,378	436	564	5,378
Equity companies	210	-	11	-	1,114	-	1,335	-	-	1,335
Proved undeveloped reserves, as of December 31, 2016										
Consolidated subsidiaries	1,626	169	31	169	1,025	74	3,094	265	-	3,359
Equity companies	36	-	6	-	443	-	485	-	-	485
Total liquids proved reserves at December 31, 2016	3,189	256	223	1,005	4,440	179	9,292	701	564	10,557
Proved developed reserves, as of December 31, 2017										
Consolidated subsidiaries	1,489	92	119	676	2,182	131	4,689	657	473	5,819
Equity companies	208	-	14	-	1,019	-	1,241	-	-	1,241
Proved undeveloped reserves, as of December 31, 2017										
Consolidated subsidiaries	2,167	337	30	137	1,426	31	4,128	355	-	4,483
Equity companies	48	-	1	6	431	-	486	-	-	486
Total liquids proved reserves at December 31, 2017	3,912	429	164	819	5,058	162	10,544	1,012	473	12,029
Proved developed reserves, as of December 31, 2018										
Consolidated subsidiaries	1,696	153	123	578	2,285	118	4,953	3,880	466	9,299
Equity companies	208	-	15	-	919	-	1,142	-	-	1,142
Proved undeveloped reserves, as of December 31, 2018										
Consolidated subsidiaries	2,616	403	78	111	1,173	35	4,416	305	-	4,721
Equity companies	56	-	-	6	433	-	495	-	-	495
Total liquids proved reserves at December 31, 2018	4,576	556	216	695	4,810	153	11,006 (1)	4,185	466	15,657

(1) See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional information on natural gas liquids proved reserves see Item 2. Properties in ExxonMobil's 2018 Form 10-K.

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent Total All Products *(1)*
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2016	19,380	1,127	1,956	793	5,329	7,041	35,626	18,892
Revisions	(1,630)	(102)	126	21	(16)	658	(943)	(3,980)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	148	-	-	-	-	-	148	135
Sales	(45)	(12)	(2)	-	-	-	(59)	(38)
Extensions/discoveries	1,156	34	6	-	-	-	1,196	453
Production	(1,223)	(107)	(427)	(43)	(392)	(342)	(2,534)	(1,153)
December 31, 2016	17,786	940	1,659	771	4,921	7,357	33,434	14,309
Attributable to noncontrolling interests		*150*						
Proportional interest in proved reserves of equity companies								
January 1, 2016	220	-	7,903	-	16,461	-	24,584	5,867
Revisions	4	-	114	-	(183)	-	(65)	171
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	5	-	-	-	5	1
Production	(13)	-	(398)	-	(1,044)	-	(1,455)	(374)
December 31, 2016	211	-	7,624	-	15,234	-	23,069	5,665
Total proved reserves at December 31, 2016	17,997	940	9,283	771	20,155	7,357	56,503	19,974
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2017	17,786	940	1,659	771	4,921	7,357	33,434	14,309
Revisions	649	206	134	(135)	(214)	33	673	1,063
Improved recovery	-	1	-	-	-	-	1	8
Purchases	982	56	-	-	-	-	1,038	771
Sales	(172)	(1)	(17)	-	-	-	(190)	(87)
Extensions/discoveries	956	269	-	-	13	-	1,238	970
Production	(1,168)	(99)	(408)	(41)	(380)	(496)	(2,592)	(1,131)
December 31, 2017	19,033	1,372	1,368	595	4,340	6,894	33,602	15,903
Attributable to noncontrolling interests		*195*						
Proportional interest in proved reserves of equity companies								
January 1, 2017	211	-	7,624	-	15,234	-	23,069	5,665
Revisions	25	-	(1,129)	-	86	-	(1,018)	(138)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	914	-	-	914	158
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-
Production	(13)	-	(331)	-	(1,072)	-	(1,416)	(367)
December 31, 2017	223	-	6,164	914	14,248	-	21,549	5,318

Total proved reserves at December 31, 2017	19,256	1,372	7,532	1,509	18,588	6,894	55,151	21,221

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(1)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2018	19,033	1,372	1,368	595	4,340	6,894	33,602	15,903
Revisions	(98)	(29)	306	38	(147)	1,065	1,135	3,626
Improved recovery	-	-	-	-	-	-	-	36
Purchases	104	-	-	-	-	-	104	27
Sales	(264)	(3)	(4)	-	-	-	(271)	(71)
Extensions/discoveries	3,658	506	3	-	1	7	4,175	1,654
Production	(1,030)	(102)	(361)	(45)	(353)	(504)	(2,395)	(1,097)
December 31, 2018	21,403	1,744	1,312	588	3,841	7,462	36,350	20,078
Attributable to noncontrolling interests		*334*						
Proportional interest in proved reserves of equity companies								
January 1, 2018	223	-	6,164	914	14,248	-	21,549	5,318
Revisions	12	-	(4,801)	(51)	102	-	(4,738)	(753)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	(38)	-	-	-	(38)	(6)
Extensions/discoveries	2	-	-	-	-	-	2	1
Production	(12)	-	(268)	-	(1,029)	-	(1,309)	(345)
December 31, 2018	225	-	1,057	863	13,321	-	15,466	4,215
Total proved reserves at December 31, 2018	21,628	1,744	2,369	1,451	17,162	7,462	51,816	24,293

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							Oil-Equivalent
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	**Total All Products *(1)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Proved developed reserves, as of December 31, 2016								
Consolidated subsidiaries	11,927	478	1,473	728	4,532	3,071	22,209	9,079
Equity companies	144	-	5,804	-	14,067	-	20,015	4,671
Proved undeveloped reserves, as of December 31, 2016								
Consolidated subsidiaries	5,859	462	186	43	389	4,286	11,225	5,230
Equity companies	67	-	1,820	-	1,167	-	3,054	994
Total proved reserves at December 31, 2016	17,997	940	9,283	771	20,155	7,357	56,503	19,974
Proved developed reserves, as of December 31, 2017								
Consolidated subsidiaries	12,649	512	1,231	584	4,030	4,420	23,426	9,724
Equity companies	154	-	4,899	-	12,898	-	17,951	4,232
Proved undeveloped reserves, as of December 31, 2017								
Consolidated subsidiaries	6,384	860	137	11	310	2,474	10,176	6,179
Equity companies	69	-	1,265	914	1,350	-	3,598	1,086
Total proved reserves at December 31, 2017	19,256	1,372	7,532	1,509	18,588	6,894	55,151	21,221
Proved developed reserves, as of December 31, 2018								
Consolidated subsidiaries	12,538	605	1,116	581	3,618	4,336	22,794	13,098
Equity companies	152	-	988	-	11,951	-	13,091	3,324
Proved undeveloped reserves, as of December 31, 2018								
Consolidated subsidiaries	8,865	1,139	196	7	223	3,126	13,556	6,980
Equity companies	73	-	69	863	1,370	-	2,375	891
Total proved reserves at December 31, 2018	21,628	1,744	2,369	1,451	17,162	7,462	51,816	24,293

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

Standardized Measure of Discounted Future Cash Flows

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

Standardized Measure of Discounted Future Cash Flows	**United States**	**Canada/ Other Americas (1)**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2016							
Future cash inflows from sales of oil and gas	118,283	50,243	15,487	40,734	118,997	28,877	372,621
Future production costs	65,585	29,798	5,362	14,447	38,727	7,643	161,562
Future development costs	31,744	11,735	9,235	8,833	13,088	8,177	82,812
Future income tax expenses	2,223	1,052	178	8,025	44,641	2,316	58,435
Future net cash flows	18,731	7,658	712	9,429	22,541	10,741	69,812
Effect of discounting net cash flows at 10%	11,039	3,443	(1,014)	2,790	12,848	5,556	34,662
Discounted future net cash flows	7,692	4,215	1,726	6,639	9,693	5,185	35,150
Equity Companies							
As of December 31, 2016							
Future cash inflows from sales of oil and gas	9,551	-	32,121	-	104,700	-	146,372
Future production costs	5,289	-	21,342	-	41,563	-	68,194
Future development costs	2,948	-	2,048	-	12,656	-	17,652
Future income tax expenses	-	-	2,206	-	16,622	-	18,828
Future net cash flows	1,314	-	6,525	-	33,859	-	41,698
Effect of discounting net cash flows at 10%	393	-	4,158	-	18,946	-	23,497
Discounted future net cash flows	921	-	2,367	-	14,913	-	18,201
Total consolidated and equity interests in standardized measure of discounted future net cash flows	8,613	4,215	4,093	6,639	24,606	5,185	53,351

(1) Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $706 million in 2016.

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/ Other Americas (1)	Europe	Africa	Asia	Australia/ Oceania	Total
			(millions of dollars)				
Consolidated Subsidiaries							
As of December 31, 2017							
Future cash inflows from sales of oil and gas	186,126	78,870	14,794	43,223	191,254	40,814	555,081
Future production costs	78,980	42,280	4,424	14,049	53,723	8,424	201,880
Future development costs	39,996	18,150	7,480	8,897	15,156	7,951	97,630
Future income tax expenses	12,879	4,527	2,790	8,818	90,614	6,017	125,645
Future net cash flows	54,271	13,913	100	11,459	31,761	18,422	129,926
Effect of discounting net cash flows at 10%	30,574	6,158	(1,255)	2,996	17,511	8,741	64,725
Discounted future net cash flows	23,697	7,755	1,355	8,463	14,250	9,681	65,201
Equity Companies							
As of December 31, 2017							
Future cash inflows from sales of oil and gas	12,643	-	28,557	2,366	127,364	-	170,930
Future production costs	5,927	-	21,120	247	48,300	-	75,594
Future development costs	3,012	-	1,913	417	11,825	-	17,167
Future income tax expenses	-	-	1,683	514	22,396	-	24,593
Future net cash flows	3,704	-	3,841	1,188	44,843	-	53,576
Effect of discounting net cash flows at 10%	1,668	-	2,116	1,045	23,744	-	28,573
Discounted future net cash flows	2,036	-	1,725	143	21,099	-	25,003
Total consolidated and equity interests in standardized measure of discounted future net cash flows	25,733	7,755	3,080	8,606	35,349	9,681	90,204
Consolidated Subsidiaries							
As of December 31, 2018							
Future cash inflows from sales of oil and gas	265,527	204,596	23,263	47,557	241,410	67,041	849,394
Future production costs	96,489	125,469	5,023	16,019	61,674	18,081	322,755
Future development costs	54,457	29,759	7,351	8,356	13,907	8,047	121,877
Future income tax expenses	25,365	9,024	8,255	10,491	124,043	10,499	187,677
Future net cash flows	89,216	40,344	2,634	12,691	41,786	30,414	217,085
Effect of discounting net cash flows at 10%	49,176	22,315	(6)	2,957	21,509	15,030	110,981
Discounted future net cash flows	40,040	18,029	2,640	9,734	20,277	15,384	106,104
Equity Companies							
As of December 31, 2018							
Future cash inflows from sales of oil and gas	17,730	-	7,264	3,777	165,471	-	194,242
Future production costs	6,474	-	2,157	249	61,331	-	70,211
Future development costs	3,359	-	1,165	370	10,295	-	15,189
Future income tax expenses	-	-	1,612	964	30,662	-	33,238
Future net cash flows	7,897	-	2,330	2,194	63,183	-	75,604

Effect of discounting net cash flows at 10%	4,104	-	713	1,712	31,503	-	38,032
Discounted future net cash flows	3,793	-	1,617	482	31,680	-	37,572
Total consolidated and equity interests in standardized measure of discounted future net cash flows	43,833	18,029	4,257	10,216	51,957	15,384	143,676

(1) Includes discounted future net cash flows attributable to noncontrolling interests in ExxonMobil consolidated subsidiaries of $1,016 million in 2017 and $2,823 million in 2018.

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

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

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

Consolidated and Equity Interests	2017		
	Consolidated Subsidiaries	Share of Equity Method Investees	Total Consolidated and Equity Interests
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2016	35,150	18,201	53,351
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	10,375	255	10,630
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(24,911)	(7,358)	(32,269)
Development costs incurred during the year	7,066	2,020	9,086

Net change in prices, lifting and development costs	51,703	12,782	64,485
Revisions of previous reserves estimates	6,580	1,193	7,773
Accretion of discount	4,951	2,124	7,075
Net change in income taxes	(25,713)	(4,214)	(29,927)
Total change in the standardized measure during the year	30,051	6,802	36,853
Discounted future net cash flows as of December 31, 2017	65,201	25,003	90,204

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

Consolidated and Equity Interests (continued)	**2018**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2017	65,201	25,003	90,204
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	9,472	(134)	9,338
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(31,706)	(9,956)	(41,662)
Development costs incurred during the year	11,500	2,762	14,262
Net change in prices, lifting and development costs	56,798	23,582	80,380
Revisions of previous reserves estimates	14,515	(2,091)	12,424
Accretion of discount	8,793	3,043	11,836
Net change in income taxes	(28,469)	(4,637)	(33,106)
Total change in the standardized measure during the year	40,903	12,569	53,472
Discounted future net cash flows as of December 31, 2018	106,104	37,572	143,676

OPERATING INFORMATION (unaudited)

	2018	2017	2016	2015	2014
Production of crude oil, natural gas liquids, bitumen and synthetic oil					
Net production	*(thousands of barrels daily)*				
United States	551	514	494	476	454
Canada/Other Americas	438	412	430	402	301
Europe	132	182	204	204	184
Africa	387	423	474	529	489
Asia	711	698	707	684	624
Australia/Oceania	47	54	56	50	59
Worldwide	2,266	2,283	2,365	2,345	2,111
Natural gas production available for sale					
Net production	*(millions of cubic feet daily)*				
United States	2,574	2,936	3,078	3,147	3,404
Canada/Other Americas	227	218	239	261	310
Europe	1,653	1,948	2,173	2,286	2,816
Africa	13	5	7	5	4
Asia	3,613	3,794	3,743	4,139	4,099
Australia/Oceania	1,325	1,310	887	677	512
Worldwide	9,405	10,211	10,127	10,515	11,145
	(thousands of oil-equivalent barrels daily)				
Oil-equivalent production *(1)*	3,833	3,985	4,053	4,097	3,969
Refinery throughput	*(thousands of barrels daily)*				
United States	1,588	1,508	1,591	1,709	1,809
Canada	392	383	363	386	394
Europe	1,422	1,510	1,417	1,496	1,454
Asia Pacific	706	690	708	647	628
Other Non-U.S.	164	200	190	194	191
Worldwide	4,272	4,291	4,269	4,432	4,476
Petroleum product sales *(2)*					
United States	2,210	2,190	2,250	2,521	2,655
Canada	510	499	491	488	496
Europe	1,556	1,597	1,519	1,542	1,555
Asia Pacific and other Eastern Hemisphere	1,200	1,164	1,140	1,124	1,085
Latin America	36	80	82	79	84
Worldwide	5,512	5,530	5,482	5,754	5,875
Gasoline, naphthas	2,217	2,262	2,270	2,363	2,452
Heating oils, kerosene, diesel oils	1,840	1,850	1,772	1,924	1,912
Aviation fuels	402	382	399	413	423
Heavy fuels	395	371	370	377	390
Specialty petroleum products	658	665	671	677	698
Worldwide	5,512	5,530	5,482	5,754	5,875
Chemical prime product sales *(2)*	*(thousands of metric tons)*				
United States	9,824	9,307	9,576	9,664	9,528
Non-U.S.	17,045	16,113	15,349	15,049	14,707
Worldwide	26,869	25,420	24,925	24,713	24,235

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

(1) 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.

INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the Registrant's Annual Report on Form 10-K for 2015).
3(ii)	By-Laws, as revised effective November 1, 2017 (incorporated by reference to Exhibit 3(ii) to the Registrant's Report on Form 8-K of October 31, 2017).
10(iii)(a.1)	2003 Incentive Program, as approved by shareholders May 28, 2003 (incorporated by reference to Exhibit 10(iii)(a.1) to the Registrant's Annual Report on Form 10-K for 2017).*
10(iii)(a.2)	Extended Provisions for Restricted Stock Agreements (incorporated by reference to Exhibit 10(iii)(a.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements – Settlement in Shares.*
10(iii)(b.1)	Short Term Incentive Program, as amended.*
10(iii)(b.2)	Earnings Bonus Unit instrument.*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant's Annual Report on Form 10-K for 2014).*
10(iii)(c.3)	ExxonMobil Additional Payments Plan.*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan.*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by reference to Exhibit 10(iii)(f.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors (incorporated by reference to Exhibit 10(iii)(f.3) to the Registrant's Annual Report on Form 10-K for 2014).*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated October 26, 2011 (incorporated by reference to Exhibit 10(iii)(f.4) to the Registrant's Annual Report on Form 10-K for 2015).*
14	Code of Ethics and Business Conduct (incorporated by reference to Exhibit 14 to the Registrant's Annual Report on Form 10-K for 2017).
21	Subsidiaries of the registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.

31.1	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.
31.2	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Financial Officer.
31.3	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting Officer.
32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.
32.2	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Financial Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
101	Interactive data files.

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

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

SIGNATURES

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

EXXON MOBIL CORPORATION

By: /s/ DARREN W. WOODS

(Darren W. Woods,
Chairman of the Board)

Dated February 27, 2019

POWER OF ATTORNEY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated and on February 27, 2019.

/s/ DARREN W. WOODS (Darren W. Woods)	Chairman of the Board (Principal Executive Officer)
/s/ SUSAN K. AVERY (Susan K. Avery)	Director
/s/ ANGELA F. BRALY (Angela F. Braly)	Director
/s/ URSULA M. BURNS (Ursula M. Burns)	Director

/s/ KENNETH C. FRAZIER (Kenneth C. Frazier)	Director
/s/ STEVEN A. KANDARIAN (Steven A. Kandarian)	Director
/s/ DOUGLAS R. OBERHELMAN (Douglas R. Oberhelman)	Director
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director
/s/ STEVEN S REINEMUND (Steven S Reinemund)	Director
/s/ WILLIAM C. WELDON (William C. Weldon)	Director
/s/ ANDREW P. SWIGER (Andrew P. Swiger)	Senior Vice President (Principal Financial Officer)
/s/ DAVID S. ROSENTHAL (David S. Rosenthal)	Vice President and Controller (Principal Accounting Officer)

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2017

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, 2017

or

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

For the transition period from   to

Commission File Number 1-2256

EXXON MOBIL CORPORATION

(Exact name of registrant as specified in its charter)

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

5959 LAS COLINAS BOULEVARD, IRVING, TEXAS 75039-2298

(Address of principal executive offices) (Zip Code)

(972) 940-6000

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, without par value (4,237,462,159 shares outstanding at January 31, 2018)	**New York Stock Exchange**

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or 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 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $80.73 on the New York Stock Exchange composite tape, was in excess of $342 billion.

Documents Incorporated by Reference: Proxy Statement for the 2018 Annual Meeting of Shareholders (Part III)

EXXON MOBIL CORPORATION
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2017

TABLE OF CONTENTS

PART I

PART II

PART III

PART IV

PART I

ITEM 1. BUSINESS

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

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

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

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

ExxonMobil has a long-standing commitment to the development of proprietary technology. We have a wide array of research programs designed to meet the needs identified in each of our business segments. Information on Company-sponsored research and development spending is contained in "Note 3: Miscellaneous Financial Information" of the Financial Section of this report. ExxonMobil held over 12 thousand active patents worldwide at the end of 2017. For technology licensed to third parties, revenues totaled approximately $89 million in 2017. 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 69.6 thousand, 71.1 thousand, and 73.5 thousand at years ended 2017, 2016 and 2015, respectively. Regular employees are defined as active executive, management, professional, technical and wage employees who work full time or part time for the Corporation and are covered by the Corporation's benefit plans and programs. Regular employees do not include employees of the company-operated retail sites (CORS). The number of CORS employees was 1.6 thousand, 1.6 thousand, and 2.1 thousand at years ended 2017, 2016 and 2015, respectively.

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 2017 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.7 billion, of which $3.3 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $5 billion in 2018 and 2019. 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. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) of the Securities Exchange Act of 1934 are made available through our website as soon as reasonably practical after we electronically file or furnish the reports to the Securities and Exchange Commission (SEC). Also available on the Corporation’s website are the Company’s Corporate Governance Guidelines and Code of Ethics and Business Conduct, as well as the charters of the audit, compensation and nominating committees of the Board of Directors. Information on our website is not incorporated into this report.

ITEM 1A. RISK FACTORS

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

Supply and Demand

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

Economic conditions. The demand for energy and petrochemicals 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, which affect the demand for energy associated with heating and cooling; increased competitiveness of alternative energy sources that have so far generally not been competitive with oil and gas without the benefit of government subsidies or mandates; 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 member countries to OPEC production quotas and the occurrence of wars, hostile actions, natural disasters, disruptions in competitors' operations, or unexpected unavailability of distribution channels that may disrupt supplies. Technological change can also alter the relative costs for competitors to find, produce, and refine oil and gas and to manufacture petrochemicals.

Other market factors. ExxonMobil's business results are also exposed to potential negative impacts due to changes in interest rates, inflation, currency exchange rates, and other local or regional market conditions.

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 (including changes that result from international treaties and accords) that could adversely affect our results, such as:

- increases in taxes, duties, or government royalty rates (including retroactive claims);
- price controls;
- changes in environmental regulations or other laws that increase our cost of compliance or reduce or delay available business opportunities (including changes in laws related to offshore drilling operations, water use, methane emissions, or hydraulic fracturing);
- adoption of regulations mandating 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, restrictive permitting, increased efficiency standards, and incentives or mandates for renewable energy. These requirements could make our products more expensive, lengthen project implementation times, and reduce demand for hydrocarbons, as well as shift hydrocarbon demand toward relatively lower-carbon sources such as natural gas. Current and pending greenhouse gas regulations 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_2 emissions from gas-fired power plants. Our future results may depend in part on the success of our research efforts and on our ability to adapt and apply the strengths of our current business model to providing the energy products of the future in a cost-competitive manner. See “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. To maintain our competitive position, especially in light of the technological nature of our businesses and the need for continuous efficiency improvement, ExxonMobil’s research and development organizations must be successful and able to adapt to a changing market and policy environment, including developing technologies to help reduce greenhouse gas emissions.

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

Cybersecurity. ExxonMobil is regularly subject to attempted cybersecurity disruptions from a variety of threat actors. If our systems for protecting against cybersecurity disruptions prove to be insufficient, ExxonMobil as well as our customers, employees, or third parties could be adversely affected. Such 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 such a cybersecurity disruption as well as in connection with resulting regulatory actions and litigation.

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

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.

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.

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 2017

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and equity companies. Gas is converted to an oil-equivalent basis at six million cubic feet per one thousand barrels. The Corporation has reported proved reserves on the basis of the average of the first-day-of-the-month price for each month during the last 12-month period. No major discovery or other favorable or adverse event has occurred since December 31, 2017, that would cause a significant change in the estimated proved reserves as of that date.

	Crude Oil	Natural Gas Liquids	Bitumen	Synthetic Oil	Natural Gas	Oil-Equivalent Basis
	(million bbls)	*(million bbls)*	*(million bbls)*	*(million bbls)*	*(billion cubic ft)*	*(million bbls)*
Proved Reserves						
Developed						
Consolidated Subsidiaries						
United States	1,137	352	-	-	12,649	3,597
Canada/Other Americas *(1)*	85	7	657	473	512	1,307
Europe	93	26	-	-	1,231	325
Africa	593	83	-	-	584	773
Asia	2,070	112	-	-	4,030	2,854
Australia/Oceania	85	46	-	-	4,420	868
Total Consolidated	4,063	626	657	473	23,426	9,724
Equity Companies						
United States	201	7	-	-	154	234
Europe	14	-	-	-	4,899	830
Africa	-	-	-	-	-	-
Asia	715	304	-	-	12,898	3,168
Total Equity Company	930	311	-	-	17,951	4,232
Total Developed	4,993	937	657	473	41,377	13,956
Undeveloped						
Consolidated Subsidiaries						
United States	1,558	609	-	-	6,384	3,231
Canada/Other Americas *(1)*	325	12	355	-	860	835
Europe	26	4	-	-	137	53
Africa	136	1	-	-	11	139
Asia	1,426	-	-	-	310	1,478
Australia/Oceania	25	6	-	-	2,474	443
Total Consolidated	3,496	632	355	-	10,176	6,179
Equity Companies						
United States	44	4	-	-	69	60
Europe	1	-	-	-	1,265	212
Africa	6	-	-	-	914	158
Asia	382	49	-	-	1,350	656
Total Equity Company	433	53	-	-	3,598	1,086
Total Undeveloped	3,929	685	355	-	13,774	7,265
Total Proved Reserves	8,922	1,622	1,012	473	55,151	21,221

(1) Other Americas includes proved developed reserves of 2 million barrels of crude oil and 42 billion cubic feet of natural gas, as well as proved undeveloped reserves of 150 million barrels of crude oil and 175 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 2017

Additions to ExxonMobil's proved reserves in 2017 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 and has a degree in Engineering. He is an active member of the Society of Petroleum Engineers (SPE). The group is staffed with individuals that have an average of more than 20 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves under the SEC guidelines. This group includes individuals who hold advanced degrees in either Engineering or Geology, and a member currently serves on the SPE Oil and Gas Reserves Committee.

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

2. Proved Undeveloped Reserves

At year-end 2017, approximately 7.3 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 34 percent of the 21.2 GOEB reported in proved reserves. This compares to the 6.2 GOEB of proved undeveloped reserves reported at the end of 2016. During the year, ExxonMobil conducted development activities that resulted in the transfer of approximately 0.7 GOEB from proved undeveloped to proved developed reserves by year-end. The largest transfers were related to the start-up of the Gorgon field and Longford Gas Conditioning Plant in Australia and drilling activity in the United States, the United Arab Emirates, and Kazakhstan. During 2017, extensions and discoveries, primarily in the United Arab Emirates, the United States, and Guyana resulted in an addition of approximately 0.9 GOEB of proved undeveloped reserves. Also, purchases, primarily in the United States and Mozambique resulted in the addition of approximately 0.9 GOEB of proved undeveloped reserves.

Overall, investments of $8 billion were made by the Corporation during 2017 to progress the development of reported proved undeveloped reserves, including $8 billion for oil and gas producing activities and in addition, nearly $100 million for other non-oil and gas producing activities such as the construction of support infrastructure and other related facilities. These investments represented 48 percent of the $16.7 billion in total reported Upstream capital and exploration expenditures. Investments made by the Corporation to develop quantities which no longer meet the SEC definition of proved reserves due to 2017 average prices are included in the $16.7 billion of Upstream capital expenditures reported above but are excluded from amounts related to progressing the development of proved undeveloped reserves.

One of ExxonMobil's requirements for reporting proved reserves is that management has made significant funding commitments toward the development of the reserves. ExxonMobil has a disciplined investment strategy and many major fields require long lead-time in order to be developed. Development projects typically take several years from the time of recording proved undeveloped reserves to the start of production and can exceed five years for large and complex projects. Proved undeveloped reserves in Canada, Kazakhstan, Australia, the Netherlands, the United States, and Qatar 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, 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 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. In Australia, proved undeveloped reserves are associated with future compression for the Gorgon Jansz LNG project. In the Netherlands, the Groningen gas field has proved undeveloped reserves related to installation of future compression.

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.

	2017		2016		2015	
	(thousands of barrels daily)					
Crude oil and natural gas liquids production	Crude Oil	NGL	Crude Oil	NGL	Crude Oil	NGL
Consolidated Subsidiaries						
United States	361	96	347	87	326	86
Canada/Other Americas	44	6	53	6	47	8
Europe	147	31	171	31	173	28
Africa	412	11	459	15	511	18
Asia	373	26	383	27	346	29
Australia/Oceania	35	19	37	19	33	17
Total Consolidated Subsidiaries	1,372	189	1,450	185	1,436	186
Equity Companies						
United States	55	2	58	2	61	3
Europe	4	-	2	-	3	-
Asia	235	64	232	65	241	68
Total Equity Companies	294	66	292	67	305	71
Total crude oil and natural gas liquids production	1,666	255	1,742	252	1,741	257
Bitumen production						
Consolidated Subsidiaries						
Canada/Other Americas	305		304		289	
Synthetic oil production						
Consolidated Subsidiaries						
Canada/Other Americas	57		67		58	
Total liquids production	2,283		2,365		2,345	
	(millions of cubic feet daily)					
Natural gas production available for sale						
Consolidated Subsidiaries						
United States	2,910		3,052		3,116	
Canada/Other Americas *(1)*	218		239		261	
Europe	1,046		1,093		1,110	
Africa	5		7		5	
Asia	906		927		1,080	
Australia/Oceania	1,310		887		677	
Total Consolidated Subsidiaries	6,395		6,205		6,249	
Equity Companies						
United States	26		26		31	
Europe	902		1,080		1,176	
Asia	2,888		2,816		3,059	
Total Equity Companies	3,816		3,922		4,266	
Total natural gas production available for sale	10,211		10,127		10,515	

	(thousands of oil-equivalent barrels daily)		
Oil-equivalent production	3,985	4,053	4,097

(1) Other Americas includes natural gas production available for sale for 2017, 2016 and 2015 of 24 million, 22 million, and 21 million cubic feet daily, respectively.

B. Production Prices and Production Costs

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

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2017				*(dollars per unit)*			
Consolidated Subsidiaries							
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
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
During 2016							
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	36.47	39.50	40.57	42.59	41.89	43.33	40.59
NGL, per barrel	16.16	18.91	22.17	26.78	17.12	23.95	18.99
Natural gas, per thousand cubic feet	1.43	1.71	4.26	1.14	1.56	3.46	2.25
Bitumen, per barrel	-	19.30	-	-	-	-	19.30
Synthetic oil, per barrel	-	43.03	-	-	-	-	43.03
Average production costs, per oil-equivalent barrel - total	10.41	21.16	12.78	12.75	6.44	7.12	11.79
Average production costs, per barrel - bitumen	-	18.25	-	-	-	-	18.25
Average production costs, per barrel - synthetic oil	-	33.64	-	-	-	-	33.64
Equity Companies							
Average production prices							
Crude oil, per barrel	38.44	-	36.13	-	39.69	-	39.41
NGL, per barrel	14.85	-	-	-	25.21	-	24.87
Natural gas, per thousand cubic feet	2.03	-	4.19	-	3.59	-	3.75

Average production costs, per oil-equivalent barrel - total	22.26	-	7.92	-	1.80	-	4.21
Total							
Average production prices							
Crude oil, per barrel	36.75	39.50	40.51	42.59	41.06	43.33	40.39
NGL, per barrel	16.13	18.91	22.17	26.78	22.85	23.95	20.56
Natural gas, per thousand cubic feet	1.44	1.71	4.22	1.14	3.09	3.46	2.83
Bitumen, per barrel	-	19.30	-	-	-	-	19.30
Synthetic oil, per barrel	-	43.03	-	-	-	-	43.03
Average production costs, per oil-equivalent barrel - total	11.18	21.16	11.21	12.75	3.77	7.12	9.89
Average production costs, per barrel - bitumen	-	18.25	-	-	-	-	18.25
Average production costs, per barrel - synthetic oil	-	33.64	-	-	-	-	33.64

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2015				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	41.87	44.30	49.04	51.01	48.30	49.56	47.75
NGL, per barrel	16.96	21.91	27.50	33.41	21.14	29.75	22.16
Natural gas, per thousand cubic feet	1.65	1.78	6.47	1.57	2.02	5.13	2.95
Bitumen, per barrel	-	25.07	-	-	-	-	25.07
Synthetic oil, per barrel	-	48.15	-	-	-	-	48.15
Average production costs, per oil-equivalent barrel - total	12.50	22.68	15.86	10.31	7.71	8.86	12.97
Average production costs, per barrel - bitumen	-	19.20	-	-	-	-	19.20
Average production costs, per barrel - synthetic oil	-	41.83	-	-	-	-	41.83
Equity Companies							
Average production prices							
Crude oil, per barrel	46.34	-	46.05	-	48.44	-	47.99
NGL, per barrel	15.37	-	-	-	32.36	-	31.75
Natural gas, per thousand cubic feet	2.05	-	6.27	-	5.83	-	5.92
Average production costs, per oil-equivalent barrel - total	22.15	-	7.75	-	1.41	-	3.89
Total							
Average production prices							
Crude oil, per barrel	42.58	44.30	48.97	51.01	48.36	49.56	47.79
NGL, per barrel	16.92	21.91	27.50	33.41	28.94	29.75	24.77
Natural gas, per thousand cubic feet	1.65	1.78	6.37	1.57	4.84	5.13	4.16
Bitumen, per barrel	-	25.07	-	-	-	-	25.07
Synthetic oil, per barrel	-	48.15	-	-	-	-	48.15
Average production costs, per oil-equivalent barrel - total	13.16	22.68	13.09	10.31	3.96	8.86	10.56
Average production costs, per barrel - bitumen	-	19.20	-	-	-	-	19.20
Average production costs, per barrel - synthetic oil	-	41.83	-	-	-	-	41.83

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

4. Drilling and Other Exploratory and Development Activities

A. Number of Net Productive and Dry Wells Drilled

	2017	2016	2015
Net Productive Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	-	-	-
Canada/Other Americas	5	2	1
Europe	-	1	1
Africa	1	1	1
Asia	-	-	2
Australia/Oceania	-	-	1
Total Consolidated Subsidiaries	6	4	6
Equity Companies			
United States	-	-	-
Europe	-	1	1
Africa	-	-	-
Asia	-	-	-
Total Equity Companies	-	1	1
Total productive exploratory wells drilled	6	5	7
Net Dry Exploratory Wells Drilled			
Consolidated Subsidiaries			
United States	-	-	1
Canada/Other Americas	-	1	-
Europe	-	-	2
Africa	2	1	-
Asia	-	-	-
Australia/Oceania	-	-	-
Total Consolidated Subsidiaries	2	2	3
Equity Companies			
United States	-	-	1
Europe	-	-	1
Africa	-	-	-
Asia	1	-	-
Total Equity Companies	1	-	2
Total dry exploratory wells drilled	3	2	5

	2017	2016	2015
Net Productive Development Wells Drilled			
Consolidated Subsidiaries			
United States	300	335	692
Canada/Other Americas	12	13	53
Europe	6	9	10
Africa	6	7	23
Asia	15	13	14
Australia/Oceania	1	-	4
Total Consolidated Subsidiaries	340	377	796
Equity Companies			
United States	154	121	390
Europe	1	2	1
Africa	-	-	-
Asia	3	3	2
Total Equity Companies	158	126	393
Total productive development wells drilled	498	503	1,189
Net Dry Development Wells Drilled			
Consolidated Subsidiaries			
United States	4	2	5
Canada/Other Americas	-	-	-
Europe	1	2	3
Africa	-	-	1
Asia	-	-	-
Australia/Oceania	-	-	-
Total Consolidated Subsidiaries	5	4	9
Equity Companies			
United States	-	-	-
Europe	-	-	-
Africa	-	-	-
Asia	-	-	-
Total Equity Companies	-	-	-
Total dry development wells drilled	5	4	9
Total number of net wells drilled	512	514	1,210

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 2017, the company's share of net production of synthetic crude oil was about 57 thousand barrels per day and share of net acreage was about 63 thousand acres in the Athabasca oil sands deposit.

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

Kearl is located approximately 40 miles north of Fort McMurray, Alberta, Canada. Bitumen is extracted from oil sands produced from open-pit mining operations, and processed through bitumen extraction and froth treatment trains. The product, a blend of bitumen and diluent, is shipped to our refineries and to other third parties. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation by pipeline and rail. During 2017, average net production at Kearl was about 174 thousand barrels per day.

5. Present Activities

A. Wells Drilling

	Year-End 2017		Year-End 2016	
	Gross	Net	Gross	Net
Wells Drilling				
Consolidated Subsidiaries				
United States	820	334	760	302
Canada/Other Americas	30	22	22	17
Europe	12	2	12	3
Africa	10	2	30	7
Asia	58	15	38	11
Australia/Oceania	3	1	4	1
Total Consolidated Subsidiaries	933	376	866	341
Equity Companies				
United States	10	1	22	3
Europe	8	3	9	4
Asia	14	4	7	2
Total Equity Companies	32	8	38	9
Total gross and net wells drilling	965	384	904	350

B. Review of Principal Ongoing Activities

UNITED STATES

ExxonMobil's year-end 2017 acreage holdings totaled 12.8 million net acres, of which 0.9 million net acres were offshore. ExxonMobil was active in areas onshore and offshore in the lower 48 states and in Alaska.

During the year, 444.9 net development wells were completed in the inland lower 48 states. Development activities focused on liquids-rich opportunities in the onshore U.S., primarily in the Permian Basin of West Texas and New Mexico and the Bakken oil play in North Dakota. In addition, gas development activities continued in the Marcellus Shale of Pennsylvania and West Virginia, the Utica Shale of Ohio and the Haynesville Shale of East Texas and Louisiana. In 2017, ExxonMobil acquired a number of oil and gas properties in the Permian Basin.

ExxonMobil’s net acreage in the Gulf of Mexico at year-end 2017 was 0.8 million acres. A total of 2.3 net development wells were completed during the year.

Participation in Alaska production and development continued with a total of 10.9 net development wells completed.

CANADA / OTHER AMERICAS

Canada

Oil and Gas Operations: ExxonMobil's year-end 2017 acreage holdings totaled 6.5 million net acres, of which 3.2 million net acres were offshore. A total of 10.8 net development wells were completed during the year. The Hebron project started up in 2017.

In Situ Bitumen Operations: ExxonMobil's year-end 2017 in situ bitumen acreage holdings totaled 0.7 million net onshore acres.

Argentina

ExxonMobil's net acreage totaled 0.3 million onshore acres at year-end 2017, and there were 4.0 net exploration and development wells completed during the year.

Guyana

ExxonMobil's net acreage totaled 5.2 million offshore acres at year-end 2017, and there were 2.3 net exploration wells completed during the year. The Liza Phase 1 project was funded in 2017.

EUROPE

Germany

A total of 2.8 million net onshore acres were held by ExxonMobil at year-end 2017, with 1.3 net development wells completed during the year.

Netherlands

ExxonMobil's net interest in licenses totaled approximately 1.5 million acres at year-end 2017, of which 1.1 million acres were onshore. A total of 1.3 net exploration and development wells were completed during the year.

Norway

ExxonMobil's net interest in licenses at year-end 2017 totaled approximately 0.1 million acres, all offshore. A total of 3.9 net development wells were completed during the year. In 2017, ExxonMobil divested approximately 81 thousand net operated acres in Norway.

United Kingdom

ExxonMobil's net interest in licenses at year-end 2017 totaled approximately 0.6 million acres, all offshore. A total of 1.2 net exploration and development wells were completed during the year. The Penguins Redevelopment project was funded in 2017.

AFRICA

Angola

ExxonMobil's net acreage totaled 0.2 million offshore acres at year-end 2017, with 5.9 net development wells completed during the year. On Block 32, development activities continued on the Kaombo Split Hub project.

Chad

ExxonMobil's net year-end 2017 acreage holdings consisted of 46 thousand onshore acres.

Equatorial Guinea

ExxonMobil's acreage totaled 0.3 million net offshore acres at year-end 2017, with 2.4 net exploration wells completed during the year.

Mozambique

ExxonMobil’s net acreage totaled approximately 0.1 million offshore acres at year-end 2017. ExxonMobil acquired an interest in Area 4 offshore Mozambique in December 2017. The Coral South Floating LNG project was funded in 2017.

Nigeria

ExxonMobil’s net acreage totaled 1.1 million offshore acres at year-end 2017, with 0.8 net development wells completed during the year.

ASIA

Azerbaijan

At year-end 2017, ExxonMobil's net acreage totaled 9 thousand offshore acres. A total of 1.3 net development wells were completed during the year.

Indonesia

At year-end 2017, ExxonMobil had 0.1 million net acres onshore. In 2017, ExxonMobil relinquished approximately 0.4 million net acres offshore.

Iraq

At year-end 2017, ExxonMobil's onshore acreage was 0.1 million net acres. A total of 4.5 net development wells were completed at the West Qurna Phase I oil field during the year. Oil field rehabilitation activities continued during 2017 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 continued exploration activities.

Kazakhstan

ExxonMobil's net acreage totaled 0.1 million acres onshore and 0.2 million acres offshore at year-end 2017. A total of 4.3 net development wells were completed during 2017. Development activities continued on the Tengiz Expansion project.

Malaysia

ExxonMobil's interests in production sharing contracts covered 2.5 million net acres offshore at year-end 2017. During the year, a total of 1.5 net development wells were completed. ExxonMobil acquired deepwater acreage offshore Sabah.

Qatar

Through our joint ventures with Qatar Petroleum, ExxonMobil's net acreage totaled 65 thousand acres offshore at year-end 2017. 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 2017.

Republic of Yemen

ExxonMobil's net acreage in the Republic of Yemen production sharing areas totaled 10 thousand acres onshore at year-end 2017.

Russia

ExxonMobil's net acreage holdings in Sakhalin at year-end 2017 were 85 thousand acres, all offshore. A total of 2.1 net exploration and development wells were completed. The Odoptu Stage 2 project started up in 2017.

At year-end 2017, ExxonMobil's net acreage in the Rosneft joint venture agreements for the Kara, Laptev, Chukchi and Black Seas was 63.6 million acres, all offshore. ExxonMobil and Rosneft formed a joint venture to evaluate the development of tight-oil reserves in western Siberia in 2013. Refer to the relevant portion of "Note 7: Equity Company Information" of the Financial Section of this report for additional information on the Corporation's participation in Rosneft joint venture activities.

Thailand

ExxonMobil's net onshore acreage in Thailand concessions totaled 21 thousand acres at year-end 2017.

United Arab Emirates

ExxonMobil's net acreage in the Abu Dhabi offshore Upper Zakum oil concession was 81 thousand acres at year-end 2017. A total of 5.3 net development wells were completed. During 2017, development activities continued on the

Upper Zakum 750 project, and agreements were signed for the Upper Zakum 1MBD (million barrels per day) project, including a 10-year extension to 2051 for the Upper Zakum concession.

AUSTRALIA / OCEANIA

Australia

ExxonMobil's year-end 2017 acreage holdings totaled 2.0 million net offshore acres. The Gas Conditioning Plant at Longford started up in 2017.

The third train of the co-venturer-operated Gorgon Jansz liquefied natural gas (LNG) project started up in 2017. The project consists of a subsea infrastructure for offshore production and transportation of the gas, a 15.6 million tonnes per year LNG facility and a 280 million cubic feet per day domestic gas plant located on Barrow Island, Western Australia.

Papua New Guinea

A total of 10.1 million net acres were held by ExxonMobil at year-end 2017, of which 5.4 million net acres were offshore. A total of 0.7 net exploration and development wells were completed during the year. The Papua New Guinea (PNG) LNG integrated development includes gas production and processing facilities in the southern PNG Highlands, onshore and offshore pipelines, and a 6.9 million tonnes per year LNG facility near Port Moresby. In 2017, ExxonMobil acquired InterOil Corporation (IOC), an exploration and production business focused on Papua New Guinea.

WORLDWIDE EXPLORATION

At year-end 2017, 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 30.1 million net acres were held at year-end 2017 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 2018 through 2020. 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 2017				Year-End 2016			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Gross and Net Productive Wells								
Consolidated Subsidiaries								
United States	20,679	8,366	27,700	15,979	20,470	8,037	32,949	19,873
Canada/Other Americas	4,877	4,618	4,273	1,646	5,024	4,767	4,362	1,668
Europe	1,016	267	664	268	1,130	323	641	253
Africa	1,222	474	15	6	1,268	494	17	7
Asia	900	299	139	82	882	299	140	82
Australia/Oceania	588	129	73	30	588	128	53	23
Total Consolidated Subsidiaries	29,282	14,153	32,864	18,011	29,362	14,048	38,162	21,906
Equity Companies								
United States	13,796	5,247	4,227	491	13,957	5,315	4,257	491
Europe	59	21	617	195	56	19	586	186
Asia	144	36	125	30	131	33	125	30
Total Equity Companies	13,999	5,304	4,969	716	14,144	5,367	4,968	707
Total gross and net productive wells	43,281	19,457	37,833	18,727	43,506	19,415	43,130	22,613

There were 30,263 gross and 25,827 net operated wells at year-end 2017 and 35,047 gross and 29,375 net operated wells at year-end 2016. The number of wells with multiple completions was 1,366 gross in 2017 and 1,209 gross in 2016.

B. Gross and Net Developed Acreage

	Year-End 2017		Year-End 2016	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Developed Acreage				
Consolidated Subsidiaries				
United States	14,836	9,026	14,678	8,958
Canada/Other Americas *(1)*	3,604	2,328	3,374	2,146
Europe	2,970	1,335	3,215	1,446
Africa	2,492	866	2,492	866
Asia	1,983	586	1,934	562
Australia/Oceania	3,262	1,068	3,020	1,005
Total Consolidated Subsidiaries	29,147	15,209	28,713	14,983
Equity Companies				
United States	930	208	929	209
Europe	4,170	1,317	4,191	1,321
Asia	628	155	628	155
Total Equity Companies	5,728	1,680	5,748	1,685
Total gross and net developed acreage	34,875	16,889	34,461	16,668

(1) Includes developed acreage in Other Americas of 375 gross and 244 net thousands of acres for 2017 and 213 gross and 109 net thousands of acres for 2016.

Separate acreage data for oil and gas are not maintained because, in many instances, both are produced from the same acreage.

C. Gross and Net Undeveloped Acreage

	Year-End 2017		Year-End 2016	
	Gross	Net	Gross	Net
	(thousands of acres)			
Gross and Net Undeveloped Acreage				
Consolidated Subsidiaries				
United States	7,506	3,489	7,854	3,637
Canada/Other Americas *(1)*	29,495	13,410	24,054	10,569
Europe	7,576	3,622	7,218	3,368
Africa	37,699	26,705	9,496	4,979
Asia	5,802	2,680	2,436	865
Australia/Oceania	15,976	11,125	8,054	5,497
Total Consolidated Subsidiaries	104,054	61,031	59,112	28,915
Equity Companies				
United States	207	77	223	81
Europe	100	25	100	25
Africa	596	149	-	-
Asia	191,147	63,633	191,147	63,633
Total Equity Companies	192,050	63,884	191,470	63,739
Total gross and net undeveloped acreage	296,104	124,915	250,582	92,654

(1) Includes undeveloped acreage in Other Americas of 18,625 gross and 8,053 net thousands of acres for 2017 and 13,106 gross and 5,146 net thousands of acres for 2016.

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 signed in 2015; the initial exploration period is five years for oil and gas, with multi-year extensions available at the discretion of the Ministry and limited relinquishments in the absence of commercial discoveries. The production period for crude oil ranges from 25 to 30 years, while the production period for natural gas ranges from 25 to 50 years.

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 December 2017. Terms for Area 4 are governed by the Exploration and Production Concession Contract (EPCC) for Area 4 Offshore of the Rovuma Block dated December 20, 2006 and Decree Law 2/2014. The EPCC expires 30 years after the approval of a plan of development for a given discovery area.

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 is 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.

Republic of Yemen

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

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.

Exploration and production activities in the Kara, Laptev, Chukchi and Black Seas are governed by joint venture agreements concluded with Rosneft in 2013 and 2014 that cover certain of Rosneft's offshore licenses. The Kara Sea licenses covered by the joint venture agreements concluded in 2013 extend through 2040 and include exploration periods through 2020 and 2022. Additional licenses in the Kara, Laptev and Chukchi Seas covered by the joint venture agreements concluded in 2014 extend through 2043 and include an exploration period through 2023. The Kara, Laptev and Chukchi Sea licenses require development plan submission within eight to eleven years from a discovery and development activities within five years of plan approval. The Black Sea exploration license extends through 2020, and a discovery is the basis for obtaining a license for production. Refer to the relevant portion of "Note 7: Equity Company Information" of the Financial Section of this report for additional information on the Corporation's participation in Rosneft joint venture activities.

Thailand

The Petroleum Act of 1971 allows production under ExxonMobil's concession for 30 years with a ten-year extension at terms generally prevalent at the time. 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 effective as of January 2006, for a term expiring March 2026. In 2013 the governing agreements were extended to 2041 and in 2017 they 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 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 2017 *(1)*

		ExxonMobil Share KBD *(2)*	ExxonMobil Interest %
United States			
Joliet	Illinois	236	100
Baton Rouge	Louisiana	503	100
Billings	Montana	60	100
Baytown	Texas	561	100
Beaumont	Texas	366	100
Total United States		1,726	
Canada			
Strathcona	Alberta	191	69.6
Nanticoke	Ontario	113	69.6
Sarnia	Ontario	119	69.6
Total Canada		423	
Europe			
Antwerp	Belgium	307	100
Fos-sur-Mer	France	133	82.9
Gravenchon	France	239	82.9
Karlsruhe	Germany	78	25
Augusta	Italy	198	100
Trecate	Italy	132	74.8
Rotterdam	Netherlands	192	100
Slagen	Norway	116	100
Fawley	United Kingdom	262	100
Total Europe		1,657	
Asia Pacific			
Altona	Australia	86	100
Fujian	China	67	25
Jurong/PAC	Singapore	592	100
Sriracha	Thailand	167	66
Total Asia Pacific		912	
Middle East			
Yanbu	Saudi Arabia	200	50
Total Worldwide		4,918	

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

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

ExxonMobil share is the greater of ExxonMobil's interest or that portion of distillation capacity normally available to ExxonMobil.

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

Retail Sites At Year-End 2017

United States	
Owned/leased	-
Distributors/resellers	10,573
Total United States	10,573
Canada	
Owned/leased	-
Distributors/resellers	1,829
Total Canada	1,829
Europe	
Owned/leased	1,843
Distributors/resellers	3,975
Total Europe	5,818
Asia Pacific	
Owned/leased	598
Distributors/resellers	946
Total Asia Pacific	1,544
Latin America	
Owned/leased	5
Distributors/resellers	785
Total Latin America	790
Middle East/Africa	
Owned/leased	226
Distributors/resellers	182
Total Middle East/Africa	408
Worldwide	
Owned/leased	2,672
Distributors/resellers	18,290
Total Worldwide	20,962

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 2017 *(1)(2)*

		Ethylene	Polyethylene	Polypropylene	Paraxylene	ExxonMobil Interest %
North America						
Baton Rouge	Louisiana	1.1	1.3	0.4	-	100
Baytown	Texas	2.3	-	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		4.6	5.1	1.1	0.9	
Europe						
Antwerp	Belgium	-	0.4	-	-	100
Fife	United Kingdom	0.4	-	-	-	50
Gravenchon	France	0.4	0.4	0.3	-	100
Meerhout	Belgium	-	0.5	-	-	100
Rotterdam	Netherlands	-	-	-	0.7	100
Total Europe		0.8	1.3	0.3	0.7	
Middle East						
Al Jubail	Saudi Arabia	0.6	0.7	-	-	50
Yanbu	Saudi Arabia	1.0	0.7	0.2	-	50
Total Middle East		1.6	1.4	0.2	-	
Asia Pacific						
Fujian	China	0.3	0.2	0.2	0.2	25
Singapore	Singapore	1.9	1.9	0.9	1.8	100
Sriracha	Thailand	-	-	-	0.5	66
Total Asia Pacific		2.2	2.1	1.1	2.5	
Total Worldwide		9.2	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

As reported in the Corporation's Form 10-Q for the second quarter of 2017, on June 20, 2017, the United States Department of Justice (DOJ) and the United States Environmental Protection Agency (EPA) notified XTO Energy Inc. (XTO) concerning alleged violations of the Clean Air Act and the Fort Berthold Indian Reservation Federal Implementation Plan regarding the alleged failure of vapor control systems to properly route tank vapors to control devices at well pads and tank farms on the Fort Berthold Indian Reservation. In January 2018, XTO, the DOJ and the EPA agreed to the terms of a Consent Decree concerning those alleged violations. XTO has agreed to pay a penalty of $320,000, install automatic tank gauging on 30 well sites, and monitor and report emissions for three years. Following signature by EPA and the DOJ, the Consent Decree is subject to a 30-day public comment period and approval by the United States Federal District Court for the District of North Dakota – Western Division, in Bismarck, North Dakota, which is expected in March 2018.

As reported in the Corporation's Form 10-Q for the second quarter of 2017, in late April 2017, the State of North Dakota Department of Health (NDDOH) and the North Dakota State Office of the Attorney General notified XTO of their interest in settling alleged violations of the North Dakota Century Code and implementing regulations regarding the alleged failure of vapor control systems to properly route tank vapors to control devices at well pads and tank farms outside the Fort Berthold Indian Reservation. On February 1, 2018, the South Central Judicial District Court in Bismarck, North Dakota, approved a Consent Decree between XTO and NDDOH concerning those alleged violations. Under the Consent Decree, XTO will pay a civil penalty of up to $665,000, but that amount may be reduced if specified corrective actions are achieved by deadlines set forth in the Consent Decree. Assuming these deadlines are met, XTO anticipates that it will pay a penalty of approximately $440,000 in the fourth quarter of 2018. XTO will monitor and report compliance with the terms of the Consent Decree for a period of two years.

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 28, 2018)

Darren W. Woods	*Chairman of the Board*	
Held current title since:	January 1, 2017	Age: 53

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 still holds as of this filing date.

Mark W. Albers	*Senior Vice President*	
Held current title since:	April 1, 2007	Age: 61

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

Neil A. Chapman	*Senior Vice President*	
Held current title since:	January 1, 2018	Age: 55

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 still holds as of this filing date.

Michael J. Dolan	*Senior Vice President*	
Held current title since:	April 1, 2008	Age: 64

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

Andrew P. Swiger	*Senior Vice President*	
Held current title since:	April 1, 2009	Age: 61

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

Jack P. Williams, Jr.	*Senior Vice President*	
Held current title since:	June 1, 2014	Age: 54

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

Bradley W. Corson	*Vice President*	
Held current title since:	March 1, 2015	Age: 56

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

Neil W. Duffin *Vice President*

Held current title since: January 1, 2017 Age: 61

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

Randall M. Ebner *Vice President and General Counsel*

Held current title since: November 1, 2016 Age: 62

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

Robert S. Franklin *Vice President*

Held current title since: May 1, 2009 Age: 60

Mr. Robert S. Franklin was President of ExxonMobil Upstream Ventures and Vice President of Exxon Mobil Corporation May 1, 2009 – February 28, 2013. He became President of ExxonMobil Gas & Power Marketing Company and Vice President of Exxon Mobil Corporation on March 1, 2013, positions he holds as of February 28, 2018.

Stephen M. Greenlee *Vice President*

Held current title since: September 1, 2010 Age: 60

Mr. Stephen M. Greenlee became President of ExxonMobil Exploration Company and Vice President of Exxon Mobil Corporation on September 1, 2010, positions he still holds as of this filing date.

Liam M. Mallon *President, ExxonMobil Development Company*

Held current title since: January 1, 2017 Age: 55

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 still holds as of this filing date.

Bryan W. Milton *Vice President*

Held current title since: August 1, 2016 Age: 53

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 still holds as of this filing date.

Sara N. Ortwein *President, XTO Energy Inc., a subsidiary of the Corporation*

Held current title since: November 1, 2016 Age: 59

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

David S. Rosenthal *Vice President and Controller*

Held current title since:	October 1, 2008 (Vice President) September 1, 2014 (Controller)	Age: 61

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

Robert N. Schleckser *Vice President and Treasurer*

Held current title since: May 1, 2011 Age: 61

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

James M. Spellings, Jr. *Vice President and General Tax Counsel*

Held current title since: March 1, 2010 Age: 56

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

John R. Verity *Vice President*

Held current title since: January 1, 2018 Age: 59

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 still holds as of this filing date.

Theodore J. Wojnar, Jr. *Vice President – Corporate Strategic Planning*

Held current title since: August 1, 2017 Age: 58

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 still holds as of this filing date.

Jeffrey J. Woodbury *Vice President – Investor Relations and Secretary*

Held current title since: July 1, 2011 (Vice President)
September 1, 2014 (Secretary) Age: 57

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

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

PART II

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

Reference is made to the "Quarterly Information" portion of the Financial Section of this report and Item 12 in Part III of this report.

Issuer Purchases of Equity Securities for Quarter Ended December 31, 2017

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 2017	-		-	
November 2017	-		-	
December 2017	-		-	
Total	-		-	(See Note 1)

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

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

ITEM 6. SELECTED FINANCIAL DATA

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	237,162	200,628	239,854	367,647	393,039
Net income attributable to ExxonMobil	19,710	7,840	16,150	32,520	32,580
Earnings per common share	4.63	1.88	3.85	7.60	7.37
Earnings per common share - assuming dilution	4.63	1.88	3.85	7.60	7.37
Cash dividends per common share	3.06	2.98	2.88	2.70	2.46
Total assets	348,691	330,314	336,758	349,493	346,808
Long-term debt	24,406	28,932	19,925	11,653	6,891

(1) Effective December 31, 2017, the Corporation revised its accounting policy election related to sales-based taxes. See Note 2: Accounting Changes of the Financial Section of this report. As a result, Sales and other operating revenue excludes previously reported sales-based taxes of $17,980 million in 2016, $19,634 million in 2015, $26,458 million in 2014 and $27,797 million in 2013.

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 28, 2018, beginning with the section entitled “Report of Independent Registered Public Accounting Firm” and continuing through “Note 20: Acquisitions”;
- “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, 2017. 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, 2017.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation’s internal control over financial reporting as of December 31, 2017, 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 2018 annual meeting of shareholders (the "2018 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 2018 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 2018 Proxy Statement.

Equity Compensation Plan Information

Plan Category	*(a)* Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	*(b)* Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	*(c)* Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans [Excluding Securities Reflected in Column (a)]
Equity compensation plans approved by security holders	37,374,885 *(1)*	-	89,100,173 *(2)(3)*
Equity compensation plans not approved by security holders	-	-	-
Total	37,374,885	-	89,100,173

(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 88,595,473 shares available for award under the 2003 Incentive Program and 504,700 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 2018 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 2018 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

Financial	Earnings After Income Taxes		Average Capital Employed		Return on Average Capital Employed		Capital and Exploration Expenditures	
	2017	2016	2017	2016	2017	2016	2017	2016
	(millions of dollars)				*(percent)*		*(millions of dollars)*	
Upstream								
United States	6,622	(4,151)	64,896	62,114	10.2	(6.7)	3,716	3,518
Non-U.S.	6,733	4,347	109,778	107,941	6.1	4.0	12,979	11,024
Total	13,355	196	174,674	170,055	7.6	0.1	16,695	14,542
Downstream								
United States	1,948	1,094	7,936	7,573	24.5	14.4	823	839
Non-U.S.	3,649	3,107	14,578	14,231	25.0	21.8	1,701	1,623
Total	5,597	4,201	22,514	21,804	24.9	19.3	2,524	2,462
Chemical								
United States	2,190	1,876	10,672	9,018	20.5	20.8	1,583	1,553
Non-U.S.	2,328	2,739	16,844	15,826	13.8	17.3	2,188	654
Total	4,518	4,615	27,516	24,844	16.4	18.6	3,771	2,207
Corporate and financing	(3,760)	(1,172)	(2,073)	(4,477)	-	-	90	93
Total	19,710	7,840	222,631	212,226	9.0	3.9	23,080	19,304

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

Operating	2017	2016		2017	2016
	(thousands of barrels daily)			*(thousands of barrels daily)*	
Net liquids production			Refinery throughput		
United States	514	494	United States	1,508	1,591
Non-U.S.	1,769	1,871	Non-U.S.	2,783	2,678
Total	2,283	2,365	Total	4,291	4,269
	(millions of cubic feet daily)			*(thousands of barrels daily)*	
Natural gas production available for sale			Petroleum product sales *(2)*		
United States	2,936	3,078	United States	2,190	2,250
Non-U.S.	7,275	7,049	Non-U.S.	3,340	3,232
Total	10,211	10,127	Total	5,530	5,482
	(thousands of oil-equivalent barrels daily)			*(thousands of metric tons)*	
Oil-equivalent production *(1)*	3,985	4,053	Chemical prime product sales *(2) (3)*		
			United States	9,307	9,576
			Non-U.S.	16,113	15,349
			Total	25,420	24,925

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

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

(3) Prime product sales are total product sales including ExxonMobil's share of equity company volumes and finished-product transfers to the Downstream.

FINANCIAL INFORMATION

	2017	2016	2015	2014	2013
	(millions of dollars, except per share amounts)				
Sales and other operating revenue *(1)*	237,162	200,628	239,854	367,647	393,039
Earnings					
Upstream	13,355	196	7,101	27,548	26,841
Downstream	5,597	4,201	6,557	3,045	3,449
Chemical	4,518	4,615	4,418	4,315	3,828
Corporate and financing	(3,760)	(1,172)	(1,926)	(2,388)	(1,538)
Net income attributable to ExxonMobil	19,710	7,840	16,150	32,520	32,580
Earnings per common share	4.63	1.88	3.85	7.60	7.37
Earnings per common share – assuming dilution	4.63	1.88	3.85	7.60	7.37
Cash dividends per common share	3.06	2.98	2.88	2.70	2.46
Earnings to average ExxonMobil share of equity (percent)	11.1	4.6	9.4	18.7	19.2
Working capital	(10,637)	(6,222)	(11,353)	(11,723)	(12,416)
Ratio of current assets to current liabilities (times)	0.82	0.87	0.79	0.82	0.83
Additions to property, plant and equipment	24,901	16,100	27,475	34,256	37,741
Property, plant and equipment, less allowances	252,630	244,224	251,605	252,668	243,650
Total assets	348,691	330,314	336,758	349,493	346,808
Exploration expenses, including dry holes	1,790	1,467	1,523	1,669	1,976
Research and development costs	1,063	1,058	1,008	971	1,044
Long-term debt	24,406	28,932	19,925	11,653	6,891
Total debt	42,336	42,762	38,687	29,121	22,699
Fixed-charge coverage ratio (times)	13.2	5.7	17.6	46.9	55.7
Debt to capital (percent)	17.9	19.7	18.0	13.9	11.2
Net debt to capital (percent) *(2)*	16.8	18.4	16.5	11.9	9.1
ExxonMobil share of equity at year-end	187,688	167,325	170,811	174,399	174,003
ExxonMobil share of equity per common share	44.28	40.34	41.10	41.51	40.14
Weighted average number of common shares outstanding (millions)	4,256	4,177	4,196	4,282	4,419
Number of regular employees at year-end (thousands) *(3)*	69.6	71.1	73.5	75.3	75.0
CORS employees not included above (thousands) *(4)*	1.6	1.6	2.1	8.4	9.8

(1) Effective December 31, 2017, the Corporation revised its accounting policy election related to sales-based taxes. See Note 2 to the financial statements, Accounting Changes. As a result, Sales and other operating revenue excludes previously reported sales-based taxes of $17,980 million for 2016, $19,634 million for 2015, $26,458 million for 2014 and $27,797 million for 2013.

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

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

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

FREQUENTLY USED TERMS

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

Cash Flow From Operations and Asset Sales

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

Cash flow from operations and asset sales	**2017**	**2016**	**2015**
		(millions of dollars)	
Net cash provided by operating activities	30,066	22,082	30,344
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	3,103	4,275	2,389
Cash flow from operations and asset sales	33,169	26,357	32,733

Capital Employed

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

Capital employed	**2017**	**2016**	**2015**
		(millions of dollars)	
Business uses: asset and liability perspective			
Total assets	348,691	330,314	336,758
Less liabilities and noncontrolling interests share of assets and liabilities			
Total current liabilities excluding notes and loans payable	(39,841)	(33,808)	(35,214)
Total long-term liabilities excluding long-term debt	(72,014)	(79,914)	(86,047)
Noncontrolling interests share of assets and liabilities	(8,298)	(8,031)	(8,286)
Add ExxonMobil share of debt-financed equity company net assets	3,929	4,233	4,447
Total capital employed	232,467	212,794	211,658
Total corporate sources: debt and equity perspective			
Notes and loans payable	17,930	13,830	18,762
Long-term debt	24,406	28,932	19,925
ExxonMobil share of equity	187,688	167,325	170,811
Less noncontrolling interests share of total debt	(1,486)	(1,526)	(2,287)
Add ExxonMobil share of equity company debt	3,929	4,233	4,447

Total capital employed	232,467	212,794	211,658

FREQUENTLY USED TERMS

Return on Average Capital Employed

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

Return on average capital employed	**2017**	**2016**	**2015**
		(millions of dollars)	
Net income attributable to ExxonMobil	19,710	7,840	16,150
Financing costs (after tax)			
Gross third-party debt	(709)	(683)	(362)
ExxonMobil share of equity companies	(204)	(225)	(170)
All other financing costs – net	515	423	88
Total financing costs	(398)	(485)	(444)
Earnings excluding financing costs	20,108	8,325	16,594
Average capital employed	222,631	212,226	208,755
Return on average capital employed – corporate total	9.0%	3.9%	7.9%

QUARTERLY INFORMATION

	2017					2016				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Volumes										
Production of crude oil,	*(thousands of barrels daily)*									
natural gas liquids, synthetic oil and bitumen	2,333	2,269	2,280	2,251	2,283	2,538	2,330	2,211	2,384	2,365
Refinery throughput	4,324	4,345	4,287	4,207	4,291	4,185	4,152	4,365	4,371	4,269
Petroleum product sales *(1)*	5,395	5,558	5,542	5,624	5,530	5,334	5,500	5,585	5,506	5,482
Natural gas production	*(millions of cubic feet daily)*									
available for sale	10,908	9,920	9,585	10,441	10,211	10,724	9,762	9,601	10,424	10,127
	(thousands of oil-equivalent barrels daily)									
Oil-equivalent production *(2)*	4,151	3,922	3,878	3,991	3,985	4,325	3,957	3,811	4,121	4,053
	(thousands of metric tons)									
Chemical prime product sales *(1)*	6,072	6,120	6,446	6,782	25,420	6,173	6,310	6,133	6,309	24,925
Summarized financial data										
Sales and other operating	*(millions of dollars)*									
revenue *(3)*	56,474	56,026	59,350	65,312	237,162	43,032	51,714	52,123	53,759	200,628
Gross profit *(4)*	13,751	12,773	14,704	13,696	54,924	9,999	11,687	11,774	8,762	42,222
Net income attributable to										
ExxonMobil *(5)*	4,010	3,350	3,970	8,380	19,710	1,810	1,700	2,650	1,680	7,840
Per share data	*(dollars per share)*									
Earnings per common share *(6)*	0.95	0.78	0.93	1.97	4.63	0.43	0.41	0.63	0.41	1.88
Earnings per common share										
– assuming dilution *(6)*	0.95	0.78	0.93	1.97	4.63	0.43	0.41	0.63	0.41	1.88
Dividends per common share	0.75	0.77	0.77	0.77	3.06	0.73	0.75	0.75	0.75	2.98
Common stock prices										
High	91.34	83.69	82.49	84.36	91.34	85.10	93.83	95.55	93.22	95.55
Low	80.31	79.26	76.05	80.01	76.05	71.55	81.99	82.29	82.76	71.55

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

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

(3) Effective December 31, 2017, the Corporation revised its accounting policy election related to sales-based taxes. See Note 2 to the financial statements, Accounting Changes. As a result, Sales and other operating revenue excludes previously reported sales-based taxes of $4,616 million for first quarter 2017, $4,799 million for second quarter 2017, $5,065 million for third quarter 2017, $4,073 million for first quarter 2016, $4,646 million for second quarter 2016, $4,644 million for third quarter 2016, $4,617 million for fourth quarter 2016, and $17,980 million for the year 2016.

(4) Gross profit equals sales and other operating revenue less estimated costs associated with products sold. Effective December 31, 2017, the Corporation revised its accounting policy election related to sales-based taxes, which reduced previously reported gross profit by the amounts shown in note (3) above. See Note 2 to the financial statements, Accounting Changes.

(5) Fourth quarter 2017 included a U.S. tax reform impact of $5,942 million and an impairment charge of $1,294 million. Fourth quarter 2016 included an impairment charge of $2,135 million.

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

There were 386,892 registered shareholders of ExxonMobil common stock at December 31, 2017. At January 31, 2018, the registered shareholders of ExxonMobil common stock numbered 384,745.

On January 31, 2018, the Corporation declared a $0.77 dividend per common share, payable March 9, 2018.

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

FUNCTIONAL EARNINGS	2017	2016	2015
	(millions of dollars, except per share amounts)		
Earnings (U.S. GAAP)			
Upstream			
United States	6,622	(4,151)	(1,079)
Non-U.S.	6,733	4,347	8,180
Downstream			
United States	1,948	1,094	1,901
Non-U.S.	3,649	3,107	4,656
Chemical			
United States	2,190	1,876	2,386
Non-U.S.	2,328	2,739	2,032
Corporate and financing	(3,760)	(1,172)	(1,926)
Net income attributable to ExxonMobil (U.S. GAAP)	19,710	7,840	16,150
Earnings per common share	4.63	1.88	3.85
Earnings per common share – assuming dilution	4.63	1.88	3.85

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

FORWARD-LOOKING STATEMENTS

Statements in this discussion regarding expectations, plans and future events or conditions are forward-looking statements. Actual future financial and operating results or conditions, including demand growth and energy source mix; government policies relating to climate change; project plans, capacities, schedules and costs; production growth and mix; rates of field decline; asset carrying values; proved reserves; financing sources; the resolution of contingencies and uncertain tax positions; and environmental and capital expenditures; could differ materially depending on a number of factors, such as changes in the supply of and demand for crude oil, natural gas, and petroleum and petrochemical products and resulting price impacts; the outcome of commercial negotiations; the impact of fiscal and commercial terms; political or regulatory events; the outcome of exploration and development projects, and other factors discussed herein and in Item 1A. Risk Factors.

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

OVERVIEW

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

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

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

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

The basis for the Long-Term Business Outlook is the Corporation's annual *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 to grow to approximately 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. As economies and populations grow, and as living standards improve for billions of people, the need for energy will continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by about 25 percent from 2016 to 2040. This demand increase is expected to be concentrated in developing countries (i.e., those that are not member nations of the Organisation for Economic Co-operation and Development).

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

Energy for transportation – including cars, trucks, ships, trains and airplanes – is expected to increase by about 30 percent from 2016 to 2040. The growth in transportation energy demand is likely to account for approximately 60 percent of the growth in liquid fuels demand worldwide over this period, even as liquids demand for light-duty vehicles is relatively flat to 2040, reflecting the impact of better fleet fuel economy and significant growth in electric cars over the period. Nearly all the world's transportation fleets are likely to continue to run on liquid fuels, which are abundant, widely available, easy to transport, and provide a large quantity of energy in small volumes.

Demand for electricity around the world is likely to increase approximately 60 percent from 2016 to 2040, with developing countries accounting 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. Meeting the expected growth in power demand will require a diverse set of energy sources. The share of coal-fired generation is likely to decline 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. Renewables in total, led by wind and solar, will account for about half of the increase in electricity supplies worldwide over the period to 2040, reaching nearly 35 percent of global electricity supplies by 2040. Natural gas and nuclear will also gain share 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.

Liquid fuels provide the largest share of global energy supplies today reflecting broad-based availability, affordability, ease of distribution, and fitness as a practical solution to meet a wide variety of needs. By 2040, global demand for liquid fuels is projected to grow to approximately 118 million barrels of oil-equivalent per day, an increase of about 20 percent from 2016. Much of this demand today is met by crude production from traditional conventional sources; these supplies will remain important as significant development activity is expected to offset much of the natural declines from these fields. At the same time, a variety of emerging supply sources – including tight oil, deepwater, oil sands, natural gas liquids and biofuels – are expected to grow 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, access to resources and timely investments will remain critical to meeting global needs with reliable, affordable supplies.

Natural gas is a versatile fuel, suitable for a wide variety of applications, and it is expected to 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. Helping meet these needs will be significant growth in supplies of unconventional gas - the natural gas found in shale and other rock formations that was once considered uneconomic to produce. In total, about

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 supply, meeting about two-thirds of global demand in 2040. Worldwide liquefied natural gas (LNG) trade will expand significantly, meeting about one-third of the increase in demand growth, with much of this supply expected to help meet rising demand in Asia Pacific.

The world's energy mix is highly diverse and will remain so through 2040. Oil is expected to remain the largest source of energy with its share remaining close to one-third in 2040. Coal is currently the second largest source of energy, but it is likely to lose that position to natural gas in the 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 be about 5 percent of world energy.

The Corporation anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from reserve increases in previously discovered fields. Technology will underpin these increases. The cost to develop and supply these resources will be significant. According to the International Energy Agency's *World Energy Outlook 2017*, the investment required to meet oil and natural gas supply requirements worldwide over the period 2017-2040 will be about $21 trillion (New Policies Scenario, measured in 2016 dollars) or approximately $860 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, by using various assumptions and tools including application of a proxy cost of carbon to estimate potential impacts on consumer demands. For purposes of the *Outlook*, a proxy cost on energy-related CO_2 emissions is assumed to reach about $80 per tonne on average in 2040 in OECD nations. China and other leading non-OECD nations are expected to trail OECD policy initiatives. Nevertheless, as people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need.

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

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

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

The upstream industry environment continued to recover in 2017 as crude oil prices increased in response to tighter supply and higher demand; gas prices also improved with increasing demand, particularly in Asia. 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 and levels of prosperity. 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 2017, our Upstream business produced 4 million oil-equivalent barrels per day. During the year, we added over 200,000 oil-equivalent barrels per day of gross production capacity through project start-ups in Eastern Canada (Hebron) and at our Sakhalin-1 operation in Russia (Odoptu Stage 2). We added 2.7 billion oil-equivalent barrels of proved reserves, reflecting a 183 percent replacement of 2017 production. We also made strategic acquisitions in Papua New Guinea, Mozambique, and U.S. tight oil, and continued to have exploration success in Guyana.

Downstream

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

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

ExxonMobil's operating results, as noted in Item 2. Properties, reflect 22 refineries, located in 14 countries, with distillation capacity of 4.9 million barrels per day and lubricant basestock manufacturing capacity of 125 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* and *Mobil 1*.

Demand growth remained strong in 2017, and margins strengthened during the year drawing on previous high inventories, particularly in North America due to Latin American demand and hurricane related refinery outages. North American refineries also benefited from cost-competitive feedstock and energy supplies as the differential between Brent and WTI widened. Margins in Europe and Asia strengthened versus 2016, with rising Asia demand and economic growth in Europe. In the near term, we see variability in refining margins, with some regions seeing weaker margins as new capacity additions are expected to outpace growth in global demand for our products, which can also be affected by global economic conditions and regulatory changes.

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

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

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

In the fuels marketing business, margins remained relatively flat in 2017. In 2017, ExxonMobil expanded its branded retail site network and progressed the multi-year transition of the direct served (i.e., dealer, company-operated) retail network in portions of Europe to a more capital-efficient Branded Wholesaler model. The company's lubricants business continues to grow, leveraging world-class brands and integration with industry-leading basestock refining capability. ExxonMobil remains a market leader in the high-value synthetic lubricants sector, despite increasing competition.

The Downstream portfolio is continually evaluated during all parts of the business cycle, and numerous asset divestments have been made over the past decade. When investing in the Downstream, ExxonMobil remains focused on selective and resilient projects. At the end of 2017, construction was nearly complete on a new delayed coker unit at the refinery in Antwerp, Belgium, to upgrade low-value bunker fuel into higher value diesel products. Construction also progressed on a proprietary hydrocracker at the refinery in Rotterdam, Netherlands, to produce higher value ultra-low sulfur diesel and Group II basestocks. In addition, an expansion in Singapore is underway to support demand growth for finished lubricants in key markets. Finally, ExxonMobil announced plans to increase production of ultra-low sulfur fuels at the Beaumont, Texas, refinery by approximately 40,000 barrels per day.

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

Chemical

Worldwide petrochemical demand remained strong in 2017, led by growing demand from Asia Pacific manufacturers of industrial and consumer products. North America continued to benefit from abundant supplies of natural gas and gas liquids, providing both low-cost feedstock and energy. Specialty product margins moderated in 2017 with capacity additions exceeding demand growth.

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

In 2017, we completed start-up of the polyethylene derivative lines in Mont Belvieu, Texas, and the adhesion hydrocarbon resin plant in Singapore. Construction continued on major expansions at our Texas facilities, including a new world-scale ethane cracker in Baytown and expansion of the polyethylene plant in Beaumont, to capitalize on low-cost feedstock and energy supplies in North America and to meet rapidly growing demand for premium polymers. The company also continued construction on the specialty elastomers plant expansion in Newport, Wales, with start-up anticipated in 2018. Construction of a new halobutyl rubber unit also progressed in Singapore to further extend our specialty product capacity in Asia Pacific. In addition, the company completed the acquisition of a petrochemical plant from Jurong Aromatics Corporation, to complement the existing petrochemical complex in Singapore and meet growing demand for chemicals products in Asia Pacific.

REVIEW OF 2017 AND 2016 RESULTS

	2017	2016	2015
		(millions of dollars)	
Earnings (U.S. GAAP)			
Net income attributable to ExxonMobil (U.S. GAAP)	19,710	7,840	16,150

Upstream

	2017	2016	2015
		(millions of dollars)	
Upstream			
United States	6,622	(4,151)	(1,079)
Non-U.S.	6,733	4,347	8,180
Total	13,355	196	7,101

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. 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. 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.

2016

Upstream earnings were $196 million in 2016 and included asset impairment charges of $2,163 million mainly relating to dry gas operations with undeveloped acreage in the Rocky Mountains region of the U.S. Earnings were down $6,905 million from 2015. Lower realizations decreased earnings by $5.3 billion. Favorable volume and mix effects increased earnings by $130 million. The impairment charges reduced earnings by $2.2 billion. All other items increased earnings by $440 million, primarily due to lower expenses partly offset by the absence of favorable tax items from the prior year. On an oil equivalent basis, production of 4.1 million barrels per day was down slightly compared to 2015. Liquids production of 2.4 million barrels per day increased 20,000 barrels per day with increased project volumes, mainly in Canada, Indonesia and Nigeria, partly offset by field decline, the impact from Canadian wildfires, and downtime notably in Nigeria. Natural gas production of 10.1 billion cubic feet per day decreased 388 million cubic feet per day from 2015 as field decline, regulatory restrictions in the Netherlands and divestments were partly offset by higher project volumes and work programs. U.S. Upstream earnings declined $3,072 million from 2015 to a loss of $4,151 million, and included impairment charges of $2,163 million. Earnings outside the U.S. were $4,347 million, down $3,833 million from the prior year.

Upstream Additional Information

	2017	2016
	(thousands of barrels daily)	
Volumes Reconciliation (Oil-equivalent production) *(1)*		
Prior Year	4,053	4,097
Entitlements - Net Interest	-	9
Entitlements - Price / Spend / Other	(62)	(23)
Quotas	-	-
Divestments	(15)	(34)
Growth / Other	9	4
Current Year	3,985	4,053

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

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

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

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

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

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

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

Downstream

	2017	2016	2015
		(millions of dollars)	
Downstream			
United States	1,948	1,094	1,901
Non-U.S.	3,649	3,107	4,656
Total	5,597	4,201	6,557

2017

Downstream earnings of $5,597 million increased $1,396 million from 2016. Stronger refining and marketing margins increased earnings by $1.5 billion, while 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 the current year. Petroleum product sales of 5.5 million barrels per day were 48,000 barrels per day higher than 2016. Earnings from the U.S. Downstream 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.

2016

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

Chemical

	2017	2016	2015
		(millions of dollars)	
Chemical			
United States	2,190	1,876	2,386
Non-U.S.	2,328	2,739	2,032
Total	4,518	4,615	4,418

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

2016

Chemical earnings of $4,615 million increased $197 million from 2015. Stronger margins increased earnings by $440 million. Favorable volume and mix effects increased earnings by $100 million. All other items decreased earnings by $340 million, primarily due to the absence of U.S. asset management gains. Prime product sales of

24.9 million metric tons were up 212,000 metric tons from 2015. U.S. Chemical earnings were $1,876 million, down $510 million from 2015 reflecting the absence of asset management gains. Non-U.S. Chemical earnings of $2,739 million were $707 million higher than the prior year.

Corporate and Financing

	2017	2016	2015
		(millions of dollars)	
Corporate and financing	(3,760)	(1,172)	(1,926)

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.

2016

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

	2017	2016	2015
		(millions of dollars)	
Net cash provided by/(used in)			
Operating activities	30,066	22,082	30,344
Investing activities	(15,730)	(12,403)	(23,824)
Financing activities	(15,130)	(9,293)	(7,037)
Effect of exchange rate changes	314	(434)	(394)
Increase/(decrease) in cash and cash equivalents	(480)	(48)	(911)
		(December 31)	
Total cash and cash equivalents	3,177	3,657	3,705

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.

Total cash and cash equivalents were $3.7 billion at the end of 2016, essentially in line with the prior year. The major sources of funds in 2016 were net income including noncontrolling interests of $8.4 billion, the adjustment for the noncash provision of $22.3 billion for depreciation and depletion, proceeds from asset sales of $4.3 billion, and a net debt increase of $4.3 billion. The major uses of funds included spending for additions to property, plant and equipment of $16.2 billion, dividends to shareholders of $12.5 billion, the adjustment for noncash deferred income tax credits of $4.4 billion, and a change in working capital, excluding cash and debt, of $1.4 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, 2017, the Corporation had unused committed short-term lines of credit of $5.4 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, 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.

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

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 2017 were $23.1 billion, reflecting the Corporation's continued active investment program. The Corporation anticipates an investment level of $24 billion in 2018.

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

Cash Flow from Operating Activities

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.

2016

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

Cash Flow from Investing Activities

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.

2016

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

Cash Flow from Financing Activities

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.

2016

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

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

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

Commitments

Set forth below is information about the outstanding commitments of the Corporation's consolidated subsidiaries at December 31, 2017. The table combines data from the Consolidated Balance Sheet and from individual notes to the Consolidated Financial Statements.

		Payments Due by Period				
Commitments	**Note Reference Number**	**2018**	**2019-2020**	**2021-2022**	**2023 and Beyond**	**Total**
			(millions of dollars)			
Long-term debt *(1)*	14	-	5,662	4,384	14,360	24,406
– Due in one year *(2)*	6	4,766	-	-	-	4,766
Asset retirement obligations *(3)*	9	777	1,856	894	9,178	12,705
Pension and other postretirement obligations *(4)*	17	2,061	1,991	1,947	14,704	20,703
Operating leases *(5)*	11	936	1,166	667	1,521	4,290
Take-or-pay and unconditional purchase obligations *(6)*		3,389	5,973	4,870	12,259	26,491
Firm capital commitments *(7)*		5,743	2,338	828	737	9,646

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 $8.8 billion as of December 31, 2017, 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 $1,327 million.

(2) The amount due in one year is included in Notes and loans payable of $17,930 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 2018 and estimated benefit payments for unfunded plans in all years.

(5) Minimum commitments for operating leases, shown on an undiscounted basis, cover drilling equipment, tankers, service stations and other properties. Total includes $611 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 $26,491 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 $9.6 billion, including $1.9 billion in the U.S. Firm capital commitments for the non-U.S. Upstream of $7.2 billion were primarily associated with projects in the United Arab Emirates, Africa, United Kingdom, Guyana, Malaysia, Norway,

Canada and Australia. The Corporation expects to fund the majority of these commitments with internally generated funds, supplemented by short-term and long-term debt as required.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2017, 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, 2017, the Corporation's unused short-term committed lines of credit totaled $5.4 billion (Note 6) and unused long-term committed lines of credit totaled $0.2 billion (Note 14). The table below shows the Corporation's fixed-charge coverage and consolidated debt-to-capital ratios. The data demonstrates the Corporation's creditworthiness.

	2017	2016	2015
Fixed-charge coverage ratio (times)	13.2	5.7	17.6
Debt to capital (percent)	17.9	19.7	18.0
Net debt to capital (percent)	16.8	18.4	16.5

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

	2017			2016		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
	(millions of dollars)					
Upstream *(1)*	3,716	12,979	16,695	3,518	11,024	14,542
Downstream	823	1,701	2,524	839	1,623	2,462
Chemical	1,583	2,188	3,771	1,553	654	2,207
Other	90	-	90	93	-	93
Total	6,212	16,868	23,080	6,003	13,301	19,304

(1) Exploration expenses included.

Capital and exploration expenditures in 2017 were $23.1 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 $24 billion in 2018. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $16.7 billion in 2017 was up 15 percent from 2016. Investments in 2017 included acquisitions in Mozambique and Brazil, U.S. onshore drilling activity 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 66 percent of total proved reserves at year-end 2017, and has been over 60 percent for the last ten years.

Capital investments in the Downstream totaled $2.5 billion in 2017, consistent with 2016, reflecting global refining project spending. Chemical capital expenditures of $3.8 billion increased $1.6 billion from 2016 mainly resulting from the acquisition of a large-scale aromatics plant in Singapore.

TAXES

	2017	2016	2015
		(millions of dollars)	
Income taxes	(1,174)	(406)	5,415
Effective income tax rate	*5%*	*13%*	*34%*
Total other taxes and duties	32,459	31,375	32,834
Total	31,285	30,969	38,249

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.

2016

Total taxes were $31.0 billion in 2016, a decrease of $7.2 billion from 2015. Income tax expense, both current and deferred, was a credit of $0.4 billion, $5.8 billion lower than 2015, reflecting lower pre-tax income. The effective tax rate, which is calculated based on consolidated company income taxes and ExxonMobil's share of equity company income taxes, was 13 percent compared to 34 percent in the prior year due primarily to a lower share of earnings in higher tax jurisdictions, favorable one-time items, and the impact of the U.S. Upstream impairment charge. Total other taxes and duties of $31.4 billion in 2016 decreased $1.5 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 has included reasonable estimates of the income tax effects of the changes in tax law and tax rate. These include amounts for the remeasurement of the deferred income tax balance from the reduction in the corporate tax rate from 35 to 21 percent and the mandatory deemed repatriation of undistributed foreign earnings and profits. ExxonMobil's significant historical investments in the United States have created large deferred income tax liabilities. Remeasurement of these deferred income tax liabilities from the 35 percent rate to 21 percent results in a one-time non-cash benefit to earnings. The Corporation has paid taxes on earnings outside the United States at tax rates on average above the historical U.S. rate of 35 percent. As a result, the deemed repatriation tax does not create a significant tax impact for ExxonMobil. The impact of tax law changes on the Corporation's financial statements could differ from its estimates due to further analysis of the new law, regulatory guidance, technical corrections legislation, or guidance under U.S. GAAP. If significant changes occur, the Corporation will provide updated information in connection with future regulatory filings.

The 21 percent corporate tax rate will reduce the tax cost of U.S. earnings from U.S. investments, although the savings may be somewhat offset by other provisions that could raise the Corporation's future tax liability. Within the normal course of business, other provisions of the tax law that are effective in 2018 are not expected to have a material effect on operating results or financial condition.

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

ENVIRONMENTAL MATTERS

Environmental Expenditures

	2017	2016
	(millions of dollars)	
Capital expenditures	1,321	1,436
Other expenditures	3,349	3,451
Total	4,670	4,887

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 2017 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.7 billion, of which $3.3 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $5 billion in 2018 and 2019. 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 2017 for environmental liabilities were $302 million ($665 million in 2016) and the balance sheet reflects accumulated liabilities of $872 million as of December 31, 2017, and $852 million as of December 31, 2016.

MARKET RISKS, INFLATION AND OTHER UNCERTAINTIES

Worldwide Average Realizations *(1)*	2017	2016	2015
Crude oil and NGL ($ per barrel)	48.91	38.15	44.77
Natural gas ($ per thousand cubic feet)	3.04	2.25	2.95

(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 $425 million annual after-tax effect on Upstream consolidated plus equity company earnings. Similarly, a $0.10 per thousand cubic feet change in the worldwide average gas realization would have approximately a $165 million annual after-tax effect on Upstream consolidated plus equity company earnings. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide broad indicators of changes in the earnings experienced in any particular period.

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

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 interest rates, currency rates and commodity prices. In addition, the Corporation uses commodity-based contracts, including derivatives, to manage commodity price risk and for trading purposes. Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivatives described in Note 13. The Corporation 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. Beginning several years ago, an extended period of increased demand for certain services and materials resulted in higher operating and capital costs. Since then, multiple market changes, including lower oil prices and reduced upstream industry activity, have contributed to lower prices for oilfield services and materials. 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, 2018, ExxonMobil adopted the Financial Accounting Standards Board's standard, *Revenue from Contracts with Customers,* as amended. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry and transaction specific requirements, and expands disclosure requirements. The standard was adopted using the Modified Retrospective method, under which prior year results are not restated, but supplemental information on the impact of the new standard must be provided for 2018 results, if material. The standard is not expected to have a material impact on the Corporation's financial statements. The cumulative effect of adoption of the new standard is de minimis.

Effective January 1, 2018, ExxonMobil adopted the Financial Accounting Standards Board's Update, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard requires investments in equity securities other than consolidated subsidiaries and equity method investments to be measured at fair value with changes in the fair value recognized through net income. Companies can elect a modified approach for equity securities that do not have a readily determinable fair value. The standard is not expected to have a material impact on the Corporation's financial statements.

Effective January 1, 2018, ExxonMobil adopted the Financial Accounting Standards Board's Update, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The update requires the service cost component of net benefit costs to be reported in the same line of the income statement as other compensation costs and the other components of net benefit costs (non-service costs) to be presented separately from the service cost component. Additionally, only the service cost component of net benefit costs is eligible for capitalization. The Corporation expects to add a new line "Non-service pension and postretirement benefit expense" to its Consolidated Statement of Income and expects to include all of these costs in its Corporate and financing segment. This line would reflect the non-service costs that were previously included in "Production and manufacturing expenses" and "Selling, general and administrative expenses". The update is not expected to have a material impact on the Corporation's financial statements.

Effective January 1, 2019, ExxonMobil will adopt the Financial Accounting Standards Board's standard, *Leases*. The standard requires all leases with an initial term greater than one year be recorded on the balance sheet as an asset and a lease liability. The Corporation is gathering and evaluating data and recently acquired a system to facilitate implementation. We are progressing an assessment of the magnitude of the effect on the Corporation's financial statements.

CRITICAL ACCOUNTING ESTIMATES

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

Oil and 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 66 percent of total proved reserves at year-end 2017 (including both consolidated and equity company reserves), a reduction from 69 percent in 2016, 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.

Unit-of-Production Depreciation

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

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

To the extent that proved reserves for a property are 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 is anticipated to be immaterial.

Impairment

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

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

Asset valuation analyses performed as part of its asset management program and other profitability reviews assist the Corporation in assessing whether events or 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 and changes in circumstances such as a history of operating losses, an indicator of potential impairment for certain assets.

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

If events or circumstances indicate that the carrying value 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. As part of its 2017 annual planning and budgeting cycle, the Corporation identified emerging trends such as increasing estimates of available natural gas supplies and ongoing reductions in the industry's costs of supply for natural gas that resulted in a reduction to the Corporation's long-term natural gas price outlooks. Based in part on these trends, the Corporation concluded that events and circumstances indicated that the carrying value of certain long-lived assets, notably North America natural gas assets and certain other assets across the remainder of its Upstream operations, may not be recoverable. Accordingly, an impairment assessment was performed which indicated that the vast majority of asset groups assessed have future undiscounted cash flow estimates that exceed their carrying values. However, the carrying values for certain asset groups in the United States exceeded the estimated cash flows. As a result, the Corporation's fourth quarter 2017 results include an after-tax charge of $0.5 billion to reduce the carrying value of those assets to fair value. The asset groups subject to this impairment charge are primarily dry gas operations with little additional development potential. In addition, the Corporation made a decision to cease development planning activities and further allocation of capital to certain non-producing assets outside the United States. The Corporation's fourth quarter 2017 results include an after-tax charge of $0.8 billion to reduce the carrying value of those assets. Other impairments during the year resulted in an after-tax charge of $0.2 billion.

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 5.5 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.

Inventories

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

Asset Retirement Obligations

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

Suspended Exploratory Well Costs

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

Consolidations

The Consolidated Financial Statements include the accounts of 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 2017 was 6.50 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 5 percent and 8 percent, respectively. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pension fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the long-term rate of return on assets would increase annual pension expense by approximately $170 million before tax.

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

Litigation Contingencies

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

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

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

Tax Contingencies

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

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

Foreign Currency Translation

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

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation's Chief Executive Officer, Principal Financial Officer, and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation's financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation's internal control over financial reporting was effective as of December 31, 2017.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, audited the effectiveness of the Corporation's internal control over financial reporting as of December 31, 2017, 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, 2017 and 2016, 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, 2017, 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, 2017 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, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 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, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, in 2017 the Corporation changed the manner in which it accounts for certain sales and value-added taxes imposed on and concurrent with revenue-producing transactions with customers and collected on behalf of governmental authorities.

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 28, 2018
We have served as the Corporation's auditor since 1934.

CONSOLIDATED STATEMENT OF INCOME

	Note Reference Number	2017	2016	2015
			(millions of dollars)	
Revenues and other income				
Sales and other operating revenue *(1)*	2	237,162	200,628	239,854
Income from equity affiliates	7	5,380	4,806	7,644
Other income		1,821	2,680	1,750
Total revenues and other income		244,363	208,114	249,248
Costs and other deductions				
Crude oil and product purchases		128,217	104,171	130,003
Production and manufacturing expenses		34,128	31,927	35,587
Selling, general and administrative expenses		10,956	10,799	11,501
Depreciation and depletion	9	19,893	22,308	18,048
Exploration expenses, including dry holes		1,790	1,467	1,523
Interest expense		601	453	311
Other taxes and duties	2, 19	30,104	29,020	30,309
Total costs and other deductions		225,689	200,145	227,282
Income before income taxes		18,674	7,969	21,966
Income taxes	19	(1,174)	(406)	5,415
Net income including noncontrolling interests		19,848	8,375	16,551
Net income attributable to noncontrolling interests		138	535	401
Net income attributable to ExxonMobil		19,710	7,840	16,150
Earnings per common share *(dollars)*	12	4.63	1.88	3.85
Earnings per common share - assuming dilution *(dollars)*	12	4.63	1.88	3.85

(1) Effective December 31, 2017, the Corporation revised its accounting policy election related to sales-based taxes. See Note 2: Accounting Changes.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	2017	2016	2015
	(millions of dollars)		
Net income including noncontrolling interests	19,848	8,375	16,551
Other comprehensive income (net of income taxes)			
Foreign exchange translation adjustment	5,352	(174)	(9,303)
Adjustment for foreign exchange translation (gain)/loss included in net income	234	-	(14)
Postretirement benefits reserves adjustment (excluding amortization)	(219)	493	2,358
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	1,165	1,086	1,448
Unrealized change in fair value of stock investments	-	-	33
Realized (gain)/loss from stock investments included in net income	-	-	27
Total other comprehensive income	6,532	1,405	(5,451)
Comprehensive income including noncontrolling interests	26,380	9,780	11,100
Comprehensive income attributable to noncontrolling interests	693	668	(496)
Comprehensive income attributable to ExxonMobil	25,687	9,112	11,596

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

CONSOLIDATED BALANCE SHEET

	Note Reference Number	Dec. 31 2017	Dec. 31 2016
		(millions of dollars)	
Assets			
Current assets			
Cash and cash equivalents		3,177	3,657
Notes and accounts receivable, less estimated doubtful amounts	6	25,597	21,394
Inventories			
Crude oil, products and merchandise	3	12,871	10,877
Materials and supplies		4,121	4,203
Other current assets		1,368	1,285
Total current assets		47,134	41,416
Investments, advances and long-term receivables	8	39,160	35,102
Property, plant and equipment, at cost, less accumulated depreciation and depletion	9	252,630	244,224
Other assets, including intangibles, net		9,767	9,572
Total assets		348,691	330,314
Liabilities			
Current liabilities			
Notes and loans payable	6	17,930	13,830
Accounts payable and accrued liabilities	6	36,796	31,193
Income taxes payable		3,045	2,615
Total current liabilities		57,771	47,638
Long-term debt	14	24,406	28,932
Postretirement benefits reserves	17	21,132	20,680
Deferred income tax liabilities	19	26,893	34,041
Long-term obligations to equity companies		4,774	5,124
Other long-term obligations		19,215	20,069
Total liabilities		154,191	156,484
Commitments and contingencies	16		
Equity			
Common stock without par value (9,000 million shares authorized, 8,019 million shares issued)		14,656	12,157
Earnings reinvested		414,540	407,831
Accumulated other comprehensive income		(16,262)	(22,239)
Common stock held in treasury (3,780 million shares in 2017 and 3,871 million shares in 2016)		(225,246)	(230,424)
ExxonMobil share of equity		187,688	167,325
Noncontrolling interests		6,812	6,505
Total equity		194,500	173,830
Total liabilities and equity		348,691	330,314

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note Reference Number	2017	2016	2015
		(millions of dollars)		
Cash flows from operating activities				
Net income including noncontrolling interests		19,848	8,375	16,551
Adjustments for noncash transactions				
Depreciation and depletion	9	19,893	22,308	18,048
Deferred income tax charges/(credits)		(8,577)	(4,386)	(1,832)
Postretirement benefits expense in excess of/(less than) net payments		1,135	(329)	2,153
Other long-term obligation provisions in excess of/(less than) payments		(610)	(19)	(380)
Dividends received greater than/(less than) equity in current earnings of equity companies		131	(579)	(691)
Changes in operational working capital, excluding cash and debt				
Reduction/(increase) - Notes and accounts receivable		(3,954)	(2,090)	4,692
- Inventories		(1,682)	(388)	(379)
- Other current assets		(117)	171	45
Increase/(reduction) - Accounts and other payables		5,104	915	(7,471)
Net (gain) on asset sales	5	(334)	(1,682)	(226)
All other items - net	5	(771)	(214)	(166)
Net cash provided by operating activities		30,066	22,082	30,344
Cash flows from investing activities				
Additions to property, plant and equipment	5	(15,402)	(16,163)	(26,490)
Proceeds associated with sales of subsidiaries, property, plant and equipment, and sales and returns of investments	5	3,103	4,275	2,389
Decrease/(increase) in restricted cash and cash equivalents		-	-	42
Additional investments and advances		(5,507)	(1,417)	(607)
Other investing activities including collection of advances		2,076	902	842
Net cash used in investing activities		(15,730)	(12,403)	(23,824)
Cash flows from financing activities				
Additions to long-term debt	5	60	12,066	8,028
Reductions in long-term debt		-	-	(26)
Additions to short-term debt		1,735	-	-
Reductions in short-term debt		(5,024)	(314)	(506)
Additions/(reductions) in commercial paper, and debt with three months or less maturity	5	2,181	(7,459)	1,759
Cash dividends to ExxonMobil shareholders		(13,001)	(12,453)	(12,090)
Cash dividends to noncontrolling interests		(184)	(162)	(170)
Changes in noncontrolling interests		(150)	-	-
Tax benefits related to stock-based awards		-	-	2
Common stock acquired		(747)	(977)	(4,039)
Common stock sold		-	6	5
Net cash used in financing activities		(15,130)	(9,293)	(7,037)
Effects of exchange rate changes on cash		314	(434)	(394)
Increase/(decrease) in cash and cash equivalents		(480)	(48)	(911)
Cash and cash equivalents at beginning of year		3,657	3,705	4,616
Cash and cash equivalents at end of year		3,177	3,657	3,705

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	ExxonMobil Share of Equity						
	Common Stock	Earnings Reinvested	Accumulated Other Comprehensive Income	Common Stock Held in Treasury	ExxonMobil Share of Equity	Non-controlling Interests	Total Equity
				(millions of dollars)			
Balance as of December 31, 2014	10,792	408,384	(18,957)	(225,820)	174,399	6,665	181,064
Amortization of stock-based awards	828	-	-	-	828	-	828
Tax benefits related to stock-based awards	116	-	-	-	116	-	116
Other	(124)	-	-	-	(124)	-	(124)
Net income for the year	-	16,150	-	-	16,150	401	16,551
Dividends - common shares	-	(12,090)	-	-	(12,090)	(170)	(12,260)
Other comprehensive income	-	-	(4,554)	-	(4,554)	(897)	(5,451)
Acquisitions, at cost	-	-	-	(4,039)	(4,039)	-	(4,039)
Dispositions	-	-	-	125	125	-	125
Balance as of December 31, 2015	11,612	412,444	(23,511)	(229,734)	170,811	5,999	176,810
Amortization of stock-based awards	796	-	-	-	796	-	796
Tax benefits related to stock-based awards	30	-	-	-	30	-	30
Other	(281)	-	-	-	(281)	-	(281)
Net income for the year	-	7,840	-	-	7,840	535	8,375
Dividends - common shares	-	(12,453)	-	-	(12,453)	(162)	(12,615)
Other comprehensive income	-	-	1,272	-	1,272	133	1,405
Acquisitions, at cost	-	-	-	(977)	(977)	-	(977)
Dispositions	-	-	-	287	287	-	287
Balance as of December 31, 2016	12,157	407,831	(22,239)	(230,424)	167,325	6,505	173,830
Amortization of stock-based awards	801	-	-	-	801	-	801
Other	(380)	-	-	-	(380)	(52)	(432)
Net income for the year	-	19,710	-	-	19,710	138	19,848
Dividends - common shares	-	(13,001)	-	-	(13,001)	(184)	(13,185)
Other comprehensive income	-	-	5,977	-	5,977	555	6,532
Acquisitions, at cost	-	-	-	(828)	(828)	(150)	(978)
Issued for acquisitions	2,078	-	-	5,711	7,789	-	7,789
Dispositions	-	-	-	295	295	-	295
Balance as of December 31, 2017	14,656	414,540	(16,262)	(225,246)	187,688	6,812	194,500

Common Stock Share Activity	**Issued**	**Held in Treasury**	**Outstanding**
		(millions of shares)	
Balance as of December 31, 2014	8,019	(3,818)	4,201
Acquisitions	-	(48)	(48)
Dispositions	-	3	3
Balance as of December 31, 2015	8,019	(3,863)	4,156
Acquisitions	-	(12)	(12)
Dispositions	-	4	4
Balance as of December 31, 2016	8,019	(3,871)	4,148
Acquisitions	-	(10)	(10)
Issued for acquisitions	-	96	96
Dispositions	-	5	5
Balance as of December 31, 2017	8,019	(3,780)	4,239

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates. Prior years' data has been reclassified in certain cases to conform to the 2017 presentation basis.

1. Summary of Accounting Policies

Principles of Consolidation

The Consolidated Financial Statements include the accounts of subsidiaries the Corporation controls. They also include the Corporation's share of the undivided interest in certain upstream assets, liabilities, revenues and expenses. Amounts representing the Corporation's interest in entities that it does not control, but over which it exercises significant influence, are included in "Investments, advances and long-term receivables". The Corporation's share of the net income of these companies is included in the Consolidated Statement of Income caption "Income from equity affiliates".

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

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

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

Revenue Recognition

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

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

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

Taxes on Sales Transactions

Beginning in 2017, the Corporation revised its reporting of certain sales and value-added taxes imposed on and concurrent with revenue-producing transactions with customers and collected on behalf of governmental authorities (sales-based taxes). This changes reporting of sales-based taxes from gross reporting (included in both “Sales and other operating revenue” and “Sales-based taxes”) to net reporting (excluded from both “Sales and other operating revenue” and “Sales-based taxes”) in the Consolidated Statement of Income. This change in reporting was applied retrospectively and does not affect earnings. Similar taxes, for which the Corporation is not considered to be an agent for the government, continue to be reported on a gross basis.

Derivative Instruments

The Corporation has the ability to use derivative instruments to offset exposures associated with commodity prices, foreign currency exchange rates and interest rates that arise from existing assets, liabilities and forecasted transactions. The gains and losses resulting from changes in the fair value of derivatives are recorded in income.

The Corporation may designate derivatives as fair value hedges or cash flow hedges. For fair value hedges, the gain or loss on the derivative and the offsetting loss or gain on the hedged item are recognized in current earnings. For cash flow hedges, the effective part of the hedge is initially reported as a component of other comprehensive income and subsequently reclassified into earnings in the period that the forecasted transaction affects earnings, and the ineffective part of the hedge is recognized immediately in earnings.

Fair Value

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

Inventories

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

Property, Plant and Equipment

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

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

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

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.

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

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

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

Asset valuation analyses performed as part of its asset management program and other profitability reviews assist the Corporation in assessing whether events or 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 and changes in circumstances such as a history of operating losses, an indicator of potential impairment for certain assets.

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

If events or circumstances indicate that the carrying value 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.

Other. Gains on sales of proved and unproved properties are only recognized when there is neither uncertainty about the recovery of costs applicable to any interest retained nor any substantial obligation for future performance by the Corporation. Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

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

Asset Retirement Obligations and Environmental Liabilities

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

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

Foreign Currency Translation

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

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

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

Stock-Based Payments

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. Accounting Changes

Effective December 31, 2017, the Corporation revised its accounting policy election related to the reporting of certain sales and value-added taxes imposed on and concurrent with revenue-producing transactions with customers and collected on behalf of governmental authorities (sales-based taxes). This changes reporting of sales-based taxes from gross reporting (included in both "Sales and other operating revenue" and "Sales-based taxes") to the preferable method of net reporting (excluded from both "Sales and other operating revenue" and "Sales-based taxes") in the Consolidated Statement of Income. The revised election makes reported revenue more consistent with ExxonMobil's role as an agent for the government and is more consistent with the reporting practices of other international major oil and gas companies and the largest U.S. companies. This change in accounting principle was applied retrospectively and does not affect net income attributable to ExxonMobil.

Also effective December 31, 2017, the Corporation reclassified U.S. Federal excise tax from "Sales-based taxes" to "Other taxes and duties". For these taxes ExxonMobil is not considered to be an agent for the government and these taxes will continue to be reported gross. The amount reclassified was $3,110 million in 2016 and $3,044 million in 2015. This change in classification was applied retrospectively and does not affect net income attributable to ExxonMobil.

	2016			2015		
	As Reported	Change	As Adjusted	As Reported	Change	As Adjusted
	(millions of dollars)					
Sales and other operating revenue	218,608	(17,980)	200,628	259,488	(19,634)	239,854
Sales-based taxes	21,090	(21,090)	-	22,678	(22,678)	-
Other taxes and duties	25,910	3,110	29,020	27,265	3,044	30,309

Effective January 1, 2018, ExxonMobil adopted the Financial Accounting Standards Board's standard, *Revenue from Contracts with Customers,* as amended. The standard establishes a single revenue recognition model for all contracts with customers, eliminates industry and transaction specific requirements, and expands disclosure requirements. The standard was adopted using the Modified Retrospective method, under which prior year results are not restated, but supplemental information on the impact of the new standard must be provided for 2018 results, if material. The standard is not expected to have a material impact on the Corporation's financial statements. The cumulative effect of adoption of the new standard is de minimis.

Effective January 1, 2018, ExxonMobil adopted the Financial Accounting Standards Board's Update, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*. The standard requires investments in equity securities other than consolidated subsidiaries and equity method investments to be measured at fair value with changes in the fair value recognized through net income. Companies can elect a modified approach for equity securities that do not have a readily determinable fair value. The standard is not expected to have a material impact on the Corporation's financial statements.

Effective January 1, 2018, ExxonMobil adopted the Financial Accounting Standards Board's Update, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The update requires the service cost component of net benefit costs to be reported in the same line of the income statement as other compensation costs and the other components of net benefit costs (non-service costs) to be presented separately from the service cost component. Additionally, only the service cost component of net benefit costs is eligible for capitalization. The Corporation expects to add a new line "Non-service pension and postretirement benefit expense" to its Consolidated Statement of Income and expects to include all of these costs in its Corporate and financing segment. This line would reflect the non-service costs that were previously included in "Production and manufacturing expenses" and "Selling, general and administrative expenses". The update is not expected to have a material impact on the Corporation's financial statements.

Effective January 1, 2019, ExxonMobil will adopt the Financial Accounting Standards Board's standard, *Leases*. The standard requires all leases with an initial term greater than one year be recorded on the balance sheet as an asset and a lease liability. The Corporation is gathering and evaluating data and recently acquired a system to facilitate implementation. We are progressing an assessment of the magnitude of the effect on the Corporation's financial statements.

3. Miscellaneous Financial Information

Research and development expenses totaled $1,063 million in 2017, $1,058 million in 2016, and $1,008 million in 2015.

Net income included before-tax aggregate foreign exchange transaction gains of $6 million in 2017 and $29 million in 2016, and a loss of $119 million in 2015.

In 2017, 2016, and 2015, net income included losses of $10 million, $295 million, and $186 million, respectively, attributable to the combined effects of LIFO inventory accumulations and drawdowns. The aggregate replacement cost of inventories was estimated to exceed their LIFO carrying values by $10.8 billion and $8.1 billion at December 31, 2017, and 2016, respectively.

Crude oil, products and merchandise as of year-end 2017 and 2016 consist of the following:

	2017	2016
	(billions of dollars)	
Crude oil	4.6	3.9
Petroleum products	4.3	3.7
Chemical products	3.3	2.8
Gas/other	0.7	0.5
Total	12.9	10.9

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	**Cumulative Foreign Exchange Translation Adjustment**	**Post-retirement Benefits Reserves Adjustment**	**Unrealized Change in Stock Investments**	**Total**
		(millions of dollars)		
Balance as of December 31, 2014	(5,952)	(12,945)	(60)	(18,957)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(8,204)	2,202	33	(5,969)
Amounts reclassified from accumulated other comprehensive income	(14)	1,402	27	1,415
Total change in accumulated other comprehensive income	(8,218)	3,604	60	(4,554)
Balance as of December 31, 2015	(14,170)	(9,341)	-	(23,511)
Current period change excluding amounts reclassified from accumulated other comprehensive income	(331)	552	-	221
Amounts reclassified from accumulated other comprehensive income	-	1,051	-	1,051
Total change in accumulated other comprehensive income	(331)	1,603	-	1,272
Balance as of December 31, 2016	(14,501)	(7,738)	-	(22,239)
Current period change excluding amounts reclassified from accumulated other comprehensive income	4,879	(170)	-	4,709
Amounts reclassified from accumulated other comprehensive income	140	1,128	-	1,268
Total change in accumulated other comprehensive income	5,019	958	-	5,977
Balance as of December 31, 2017	(9,482)	(6,780)	-	(16,262)

Amounts Reclassified Out of Accumulated Other Comprehensive Income - Before-tax Income/(Expense)	**2017**	**2016**	**2015**
		(millions of dollars)	
Foreign exchange translation gain/(loss) included in net income (Statement of Income line: Other income)	(234)	-	14
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs *(1)*	(1,656)	(1,531)	(2,066)
Realized change in fair value of stock investments included in net income (Statement of Income line: Other income)	-	-	(42)

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

Income Tax (Expense)/Credit For Components of Other Comprehensive Income	**2017**	**2016**	**2015**
		(millions of dollars)	
Foreign exchange translation adjustment	67	43	170
Postretirement benefits reserves adjustment (excluding amortization)	201	(247)	(1,192)
Amortization and settlement of postretirement benefits reserves adjustment included in net periodic benefit costs	(491)	(445)	(618)

Unrealized change in fair value of stock investments	-	-	(17)
Realized change in fair value of stock investments included in net income	-	-	(15)
Total	(223)	(649)	(1,672)

5. Cash Flow Information

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

For 2017, the “Net (gain) on asset sales” on the Consolidated Statement of Cash Flows includes before-tax amounts from the sale of service stations in multiple countries, Upstream asset transactions in the U.S., and the sale of ExxonMobil’s operated Upstream business in Norway. For 2016, the number includes before-tax amounts from the sale of service stations in Canada, the sale of Upstream properties in the U.S., and the sale of aviation fueling operations across multiple countries. For 2015, the number includes before-tax amounts from the sale of service stations in Europe, the sale of Upstream properties in the U.S., the sale of ExxonMobil’s interests in Chemical and Refining joint ventures, and the sale of the Torrance refinery. These net gains are reported in “Other income” on the Consolidated Statement of Income.

In 2017, the “Additions/(reductions) in commercial paper, and debt with three months or less maturity” on the Consolidated Statement of Cash Flows includes a net $121 million repayment of commercial paper with maturity over three months. The gross amount issued was $3.6 billion, while the gross amount repaid was $3.7 billion. In 2016, the number includes a net $608 million addition of commercial paper with maturity over three months. The gross amount issued was $3.9 billion, while the gross amount repaid was $3.3 billion. In 2015, the number includes a net $358 million addition of commercial paper with maturity over three months. The gross amount issued was $8.1 billion, while the gross amount repaid was $7.7 billion.

In 2017, the Corporation completed the acquisitions of InterOil Corporation and of companies that own certain oil and gas properties in the Permian basin and other assets. These transactions included a significant noncash component. Additional information is provided in Note 20.

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

	2017	2016	2015
		(millions of dollars)	
Cash payments for interest	1,132	818	586
Cash payments for income taxes	7,510	4,214	7,269

6. Additional Working Capital Information

	Dec. 31 2017	Dec. 31 2016
	(millions of dollars)	
Notes and accounts receivable		
Trade, less reserves of $72 million and $75 million	21,274	16,033
Other, less reserves of $539 million and $627 million	4,323	5,361
Total	25,597	21,394
Notes and loans payable		
Bank loans	115	143
Commercial paper	13,049	10,727
Long-term debt due within one year	4,766	2,960
Total	17,930	13,830
Accounts payable and accrued liabilities		

Trade payables	21,701	17,801
Payables to equity companies	5,453	4,748
Accrued taxes other than income taxes	3,311	2,653
Other	6,331	5,991
Total	36,796	31,193

The Corporation has short-term committed lines of credit of $5.4 billion which were unused as of December 31, 2017. These lines are available for general corporate purposes.

The weighted-average interest rate on short-term borrowings outstanding was 1.3 percent and 0.6 percent at December 31, 2017, and 2016, respectively.

7. Equity Company Information

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

The share of total equity company revenues from sales to ExxonMobil consolidated companies was 15 percent, 14 percent and 15 percent in the years 2017, 2016 and 2015, respectively.

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

In 2013 and 2014, the Corporation and Rosneft established various entities to conduct exploration and research activities. In 2014, the European Union and United States imposed sanctions relating to the Russian energy sector. In the latter half of 2017, the United States codified and expanded sanctions against Russia. With respect to the foregoing, the Corporation and its affiliates continue to comply with all applicable laws, rules and regulations. In late 2017, the Corporation decided to withdraw from these joint ventures. The Corporation expects it will formally initiate the withdrawal in 2018. The decision to withdraw resulted in an after-tax loss of $0.2 billion.

In 2017, the Corporation invested about $3 billion to acquire shares in four joint venture companies, resulting in a 25 percent indirect interest in the natural gas-rich Area 4 block offshore Mozambique. The transaction was completed on December 13, 2017. The investments are accounted for using the equity method of accounting.

	2017		2016		2015	
Equity Company Financial Summary	Total	ExxonMobil Share	Total	ExxonMobil Share	Total	ExxonMobil Share
			(millions of dollars)			
Total revenues	94,791	29,340	80,247	24,668	111,866	34,297
Income before income taxes	29,748	8,498	22,269	6,509	36,379	10,670
Income taxes	8,421	2,236	6,334	1,701	11,048	3,019
Income from equity affiliates	21,327	6,262	15,935	4,808	25,331	7,651
Current assets	35,367	12,050	34,412	11,392	32,879	11,244
Long-term assets	122,221	34,931	109,646	32,357	109,684	32,878
Total assets	157,588	46,981	144,058	43,749	142,563	44,122
Current liabilities	21,725	6,348	20,507	5,765	22,947	6,738
Long-term liabilities	59,736	17,056	62,110	17,288	60,388	17,165
Net assets	76,127	23,577	61,441	20,696	59,228	20,219

A list of significant equity companies as of December 31, 2017, together with the Corporation's percentage ownership interest, is detailed below:

	Percentage Ownership Interest
Upstream	
Aera Energy LLC	48
Barzan Gas Company Limited	7
BEB Erdgas und Erdoel GmbH & Co. KG	50
Cameroon Oil Transportation Company S.A.	41
Cross Timbers Energy, LLC	50
Golden Pass LNG Terminal LLC	18
Marine Well Containment Company LLC	10
Mozambique Rovuma Venture, S.p.A.	36
Nederlandse Aardolie Maatschappij B.V.	50
Qatar Liquefied Gas Company Limited (2)	24
Ras Laffan Liquefied Natural Gas Company Limited	25
Ras Laffan Liquefied Natural Gas Company Limited (II)	31
Ras Laffan Liquefied Natural Gas Company Limited (3)	30
South Hook LNG Terminal Company Limited	24
Tengizchevroil, LLP	25
Terminale GNL Adriatico S.r.l.	71
Downstream	
Fujian Refining & Petrochemical Co. Ltd.	25
Permian Express Partners LLC	12
Saudi Aramco Mobil Refinery Company Ltd.	50
Chemical	
Al-Jubail Petrochemical Company	50
Infineum Italia s.r.l.	50
Infineum Singapore Pte. Ltd.	50
Infineum USA L.P.	50
Saudi Yanbu Petrochemical Co.	50

8. Investments, Advances and Long-Term Receivables

	Dec. 31, 2017	Dec. 31, 2016
	(millions of dollars)	
Companies carried at equity in underlying assets		
Investments	24,354	20,810
Advances	9,112	9,443
Total equity company investments and advances	33,466	30,253
Companies carried at cost or less and stock investments carried at fair value	174	154
Long-term receivables and miscellaneous investments at cost or less, net of reserves of $5,432 million and $4,141 million	5,520	4,695
Total	39,160	35,102

9. Property, Plant and Equipment and Asset Retirement Obligations

Property, Plant and Equipment	December 31, 2017		December 31, 2016	
	Cost	Net	Cost	Net
	(millions of dollars)			
Upstream	371,904	200,291	355,265	195,904
Downstream	50,343	21,732	47,915	20,588
Chemical	37,966	20,117	34,098	17,401
Other	16,972	10,490	16,637	10,331
Total	477,185	252,630	453,915	244,224

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. As part of its 2017 annual planning and budgeting cycle, the Corporation identified emerging trends such as increasing estimates of available natural gas supplies and ongoing reductions in the industry's costs of supply for natural gas that resulted in a reduction to the Corporation's long-term natural gas price outlooks. Based in part on these trends, the Corporation concluded that events and circumstances indicated that the carrying value of certain long-lived assets, notably North America natural gas assets and certain other assets across the remainder of its Upstream operations, may not be recoverable. Accordingly, an impairment assessment was performed which indicated that the vast majority of asset groups assessed have future undiscounted cash flow estimates that exceed their carrying values. However, the carrying values for certain asset groups in the United States exceeded the estimated cash flows. As a result, the Corporation's fourth quarter 2017 results include a before-tax charge of $0.8 billion to reduce the carrying value of those assets to fair value. The asset groups subject to this impairment charge are primarily dry gas operations with little additional development potential. In addition, the Corporation made a decision to cease development planning activities and further allocation of capital to certain non-producing assets outside the United States resulting in a before-tax charge of $0.9 billion to reduce the carrying value of those assets that are included in Property, Plant and Equipment. Other impairments during the year resulted in a before-tax charge of $0.3 billion. The impairment charges are recognized primarily in the line "Depreciation and depletion" on the Consolidated Statement of Income.

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 5.5 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.

Accumulated depreciation and depletion totaled $224,555 million at the end of 2017 and $209,691 million at the end of 2016. Interest capitalized in 2017, 2016 and 2015 was $749 million, $708 million and $482 million, respectively.

Asset Retirement Obligations

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

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

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

	2017	2016
	(millions of dollars)	
Beginning balance	13,243	13,704
Accretion expense and other provisions	780	740
Reduction due to property sales	(906)	(134)
Payments made	(730)	(549)
Liabilities incurred	128	204
Foreign currency translation	611	(513)
Revisions	(421)	(209)
Ending balance	12,705	13,243

The long-term Asset Retirement Obligations were $11,928 million and $12,352 million at December 31, 2017, and 2016, respectively, and are included in Other long-term obligations.

10. Accounting for Suspended Exploratory Well Costs

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

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

Change in capitalized suspended exploratory well costs:

	2017	2016	2015
	(millions of dollars)		
Balance beginning at January 1	4,477	4,372	3,587
Additions pending the determination of proved reserves	906	180	847
Charged to expense	(1,205)	(111)	(5)
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(497)	-	(43)
Divestments/Other	19	36	(14)
Ending balance at December 31	3,700	4,477	4,372
Ending balance attributed to equity companies included above	306	707	696

Period end capitalized suspended exploratory well costs:

	2017	2016	2015
	(millions of dollars)		
Capitalized for a period of one year or less	906	180	847
Capitalized for a period of between one and five years	1,345	2,981	2,386
Capitalized for a period of between five and ten years	1,064	911	826
Capitalized for a period of greater than ten years	385	405	313
Capitalized for a period greater than one year - subtotal	2,794	4,297	3,525
Total	3,700	4,477	4,372

Exploration activity often involves drilling multiple wells, over a number of years, to fully evaluate a project. The table below provides a breakdown of the number of projects with only exploratory well costs capitalized for a period of one year or less and those that have had exploratory well costs capitalized for a period greater than one year.

	2017	2016	2015
Number of projects that only have exploratory well costs capitalized for a period of one year or less	11	2	4
Number of projects that have exploratory well costs capitalized for a period of greater than one year	46	58	55
Total	57	60	59

Of the 46 projects that have exploratory well costs capitalized for a period greater than one year as of December 31, 2017, 10 projects have drilling in the preceding year or exploratory activity planned in the next two years, while the remaining 36 projects are those with completed exploratory activity progressing toward development.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The table below provides additional detail for those 36 projects, which total $1,639 million.

Country/Project	Dec. 31, 2017	Years Wells Drilled	Comment
	(millions of dollars)		
Angola			
- AB32 Central NE Hub	69	2006 - 2014	Evaluating development plan for tieback to existing production facilities.
- Kaombo Split Hub Phase 2	20	2005 - 2006	Evaluating development plan to tie into planned production facilities.
- Perpetua-Zinia-Acacia	15	2008 - 2009	Oil field near Pazflor development, awaiting capacity in existing/ planned infrastructure.
Argentina			
- La Invernada	72	2014	Evaluating development plan to tie into planned infrastructure.
Australia			
- East Pilchard	8	2001	Gas field near Kipper/Tuna development, awaiting capacity in existing/ planned infrastructure.
- SE Longtom	12	2010	Gas field near Tuna development, awaiting capacity in existing/ planned infrastructure.
- SE Remora	36	2010	Gas field near Marlin development, awaiting capacity in existing/ planned infrastructure.
Indonesia			
- Kedung Keris	11	2011	Development activity under way to tie into planned production facilities.
Iraq			
- Kurdistan Pirmam	109	2015	Evaluating commercialization alternatives, while waiting for government approval to enter Gas Holding Period.
Kazakhstan			
- Kairan	53	2004 - 2007	Evaluating commercialization and field development alternatives, while continuing discussions with the government regarding the development plan.
- Kalamkas	18	2006 - 2009	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
Malaysia			
- Bindu	2	1995	Awaiting capacity in existing/planned infrastructure.
Nigeria			
- Bolia	15	2002 - 2006	Evaluating development plan, while continuing discussions with the government regarding regional hub strategy.
- Bosi	79	2002 - 2006	Development activity under way, while continuing discussions with the

			government regarding development plan.
- Bosi Central	16	2006	Development activity under way, while continuing discussions with the government regarding development plan.
- Erha Northeast	26	2008	Evaluating development plan for tieback to existing production facilities.
- OML 138 Ukot SW	41	2014	Evaluating development plan for tieback to existing production facilities.
- OML 138 Ukot SS	13	2015	Evaluating development plan for tieback to existing production facilities.
- Pegi	32	2009	Awaiting capacity in existing/planned infrastructure.
- Satellite Field Development Phase 2	12	2013	Evaluating development plan to tie into planned production facilities.
- Other (3 projects)	7	2002	Evaluating and pursuing development of several additional discoveries.
Norway			
- Gamma	14	2008 - 2009	Evaluating development plan for tieback to existing production facilities.
- Lavrans	16	1995 - 1999	Evaluating development plan, awaiting capacity in existing Kristin production facility.
- Other (7 projects)	27	2008 - 2014	Evaluating development plans, including potential for tieback to existing production facilities.
Papua New Guinea			
- Juha	28	2007	Progressing development plans to tie into existing LNG facilities.

Country/Project	Dec. 31, 2017	Years Wells Drilled	Comment
	(millions of dollars)		
Republic of Congo			
- Mer Tres Profonde Sud	56	2000 - 2007	Evaluating development alternatives, while continuing discussions with the government regarding development plan.
Romania			
- Neptun Deep	536	2012 - 2016	Continuing discussions with the government regarding development plan.
Vietnam			
- Blue Whale	296	2011 - 2015	Development planning activity under way, while continuing commercial discussions with the government.
Total 2017 (36 projects)	1,639		

11. Leased Facilities

At December 31, 2017, the Corporation and its consolidated subsidiaries held noncancelable operating charters and leases covering drilling equipment, tankers, service stations and other properties with minimum undiscounted lease commitments totaling $4,290 million as indicated in the table. Estimated related sublease rental income from noncancelable subleases totals $36 million.

	Lease Payments Under Minimum Commitments		
	Drilling Rigs and Related Equipment	Other	Total
	(millions of dollars)		
2018	169	767	936
2019	131	537	668
2020	101	397	498
2021	70	297	367
2022	41	259	300
2023 and beyond	99	1,422	1,521
Total	611	3,679	4,290

Net rental cost under both cancelable and noncancelable operating leases incurred during 2017, 2016 and 2015 were as follows:

	2017	2016	2015
	(millions of dollars)		
Rental cost			
Drilling rigs and related equipment	792	1,274	1,853
Other (net of sublease rental income)	1,826	1,817	2,076
Total	2,618	3,091	3,929

12. Earnings Per Share

Earnings per common share	**2017**	**2016**	**2015**
Net income attributable to ExxonMobil *(millions of dollars)*	19,710	7,840	16,150
Weighted average number of common shares outstanding *(millions of shares)*	4,256	4,177	4,196
Earnings per common share *(dollars) (1)*	4.63	1.88	3.85
Dividends paid per common share *(dollars)*	3.06	2.98	2.88

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

13. Financial Instruments and Derivatives

Financial Instruments. The fair value of financial instruments is determined by reference to observable market data and other valuation techniques as appropriate. The only category of financial instruments where the difference between fair value and recorded book value is notable is long-term debt. The estimated fair value of total long-term debt, excluding capitalized lease obligations, was $23.7 billion and $28.0 billion at December 31, 2017, and 2016, respectively, as compared to recorded book values of $23.1 billion and $27.7 billion at December 31, 2017, and 2016, respectively.

The fair value of long-term debt by hierarchy level at December 31, 2017, is: Level 1 $23,529 million; Level 2 $170 million; and Level 3 $6 million.

Derivative Instruments. The Corporation's size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation's enterprise-wide risk from changes in interest rates, currency rates and commodity prices. In addition, the Corporation uses commodity-based contracts, including derivatives, to manage commodity price risk and for trading purposes. Credit risk associated with the Corporation's derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. The Corporation believes that there are no material market or credit risks to the Corporation's financial position, results of operations or liquidity as a result of the derivatives. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

The estimated fair value of derivative instruments outstanding and recorded on the balance sheet was a net liability of $38 million at year-end 2017 and a net liability of $22 million at year-end 2016. Assets and liabilities associated with derivatives are usually recorded either in "Other current assets" or "Accounts payable and accrued liabilities".

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

The Corporation recognized a before-tax gain or (loss) related to derivative instruments of $(99) million, $(81) million and $39 million during 2017, 2016 and 2015, respectively. Income statement effects associated with derivatives are usually recorded either in "Sales and other operating revenue" or "Crude oil and product purchases".

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

14. Long-Term Debt

At December 31, 2017, long-term debt consisted of $23,736 million due in U.S. dollars and $670 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $4,766 million, which matures within one year and is included in current liabilities. The amounts of long-term debt, including capitalized lease obligations, maturing in each of the four years after December 31, 2018, in millions of dollars, are: 2019 – $4,045; 2020 – $1,617; 2021 – $2,549; and 2022 – $1,835. At December 31, 2017, the Corporation's unused long-term credit lines were $0.2 billion.

Summarized long-term debt at year-end 2017 and 2016 are shown in the table below:

	Average Rate *(1)*	**2017**	**2016**
		(millions of dollars)	
Exxon Mobil Corporation			
1.305% notes due 2018		-	1,600
1.439% notes due 2018		-	1,000
Floating-rate notes due 2018 *(Issued 2016)*		-	750
Floating-rate notes due 2018 *(Issued 2015)*		-	500
1.819% notes due 2019		1,750	1,750
1.708% notes due 2019		1,250	1,250
Floating-rate notes due 2019 *(Issued 2014)*	1.345%	500	500
Floating-rate notes due 2019 *(Issued 2016)*	1.953%	250	250
1.912% notes due 2020		1,500	1,500
2.222% notes due 2021		2,500	2,500
2.397% notes due 2022		1,150	1,150
Floating-rate notes due 2022	1.557%	500	500
2.726% notes due 2023		1,250	1,250
3.176% notes due 2024		1,000	1,000
2.709% notes due 2025		1,750	1,750
3.043% notes due 2026		2,500	2,500
3.567% notes due 2045		1,000	1,000
4.114% notes due 2046		2,500	2,500
XTO Energy Inc. *(2)*			
5.500% senior notes due 2018		-	371
6.500% senior notes due 2018		-	453
6.100% senior notes due 2036		195	197
6.750% senior notes due 2037		302	304
6.375% senior notes due 2038		232	233
Mobil Corporation			
8.625% debentures due 2021		250	249
Industrial revenue bonds due 2019-2051	0.764%	2,559	2,559
Other U.S. dollar obligations		162	103
Other foreign currency obligations		34	57
Capitalized lease obligations	8.504%	1,327	1,225
Debt issuance costs		(55)	(69)
Total long-term debt		24,406	28,932

(1) Average effective interest rate for debt and average imputed interest rate for capital leases at December 31, 2017.

(2) Includes premiums of $102 million in 2017 and $138 million in 2016.

15. Incentive Program

The 2003 Incentive Program provides for grants of stock options, stock appreciation rights (SARs), restricted stock and other forms of award. Awards may be granted to eligible employees of the Corporation and those affiliates at least 50 percent owned. Outstanding awards are subject to certain forfeiture provisions contained in the program or award instrument. Options and SARs may be granted at prices not less than 100 percent of market value on the date of grant and have a maximum life of 10 years. The maximum number of shares of stock that may be issued under the 2003 Incentive Program is 220 million. Awards that are forfeited, expire or are settled in cash, do not count against this maximum limit. The 2003 Incentive Program does not have a specified term. New awards may be made until the available shares are depleted, unless the Board terminates the plan early. At the end of 2017, remaining shares available for award under the 2003 Incentive Program were 89 million.

Restricted Stock and Restricted Stock Units. Awards totaling 8,916 thousand, 9,583 thousand, and 9,681 thousand of restricted (nonvested) common stock units were granted in 2017, 2016 and 2015, respectively. Compensation expense for these awards is based on the price of the stock at the date of grant and is recognized in income over the requisite service period. Shares for these awards are issued to employees from treasury stock. The units that are settled in cash are recorded as liabilities and their changes in fair value are recognized over the vesting period. During the applicable restricted periods, the shares and units may not be sold or transferred and are subject to forfeiture. The majority of the awards have graded vesting periods, with 50 percent of the shares and units in each award vesting after three years and the remaining 50 percent vesting after seven years. Awards granted to a small number of senior executives have vesting periods of five years for 50 percent of the award and of 10 years or retirement, whichever occurs later, for the remaining 50 percent of the award.

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

The following tables summarize information about restricted stock and restricted stock units for the year ended December 31, 2017.

	2017	
Restricted stock and units outstanding	**Shares**	**Weighted Average Grant-Date Fair Value per Share**
	(thousands)	*(dollars)*
Issued and outstanding at January 1	43,833	84.43
2016 award issued in 2017	9,582	87.70
Vested	(10,136)	80.71
Forfeited	(2,201)	80.11
Issued and outstanding at December 31	41,078	86.34

Value of restricted stock and units	**2017**	**2016**	**2015**
Grant price *(dollars)*	81.89	87.70	81.27
Value at date of grant:		*(millions of dollars)*	
Restricted stock and units settled in stock	667	771	727
Units settled in cash	63	69	60
Total value	730	840	787

As of December 31, 2017, there was $2,049 million of unrecognized compensation cost related to the nonvested restricted awards. This cost is expected to be recognized over a weighted-average period of 4.5 years. The compensation cost charged against income for the restricted stock and restricted stock units was $856 million, $880 million and $855 million for 2017, 2016 and 2015, respectively. The income tax benefit recognized in income related to this compensation expense was $78 million, $80 million and $78 million for the same periods, respectively. The fair value of shares and units vested in 2017, 2016 and 2015 was $826 million, $851 million and $808 million, respectively. Cash payments of $64 million, $67 million and $64 million for vested restricted stock units settled in cash were made in 2017, 2016 and 2015, respectively.

16. Litigation and Other Contingencies

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

Other Contingencies. The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2017, for guarantees relating to notes, loans and performance under contracts. Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure.

	December 31, 2017		
	Equity Company Obligations *(1)*	**Other Third-Party Obligations**	**Total**
		(millions of dollars)	
Guarantees			
Debt-related	98	270	368
Other	1,191	4,514	5,705
Total	1,289	4,784	6,073

(1) ExxonMobil share.

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

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

On September 6, 2007, affiliates of ExxonMobil filed a Request for Arbitration with the International Centre for Settlement of Investment Disputes (ICSID). The ICSID Tribunal issued a decision on June 10, 2010, finding that it had jurisdiction to proceed on the basis of the Netherlands-Venezuela Bilateral Investment Treaty. On October 9, 2014, the ICSID Tribunal issued its final award finding in favor of the ExxonMobil affiliates and awarding $1.6 billion as of the date of expropriation, June 27, 2007, and interest from that date at 3.25 percent compounded annually until the date of payment in full. The Tribunal also noted that one of the Cerro Negro Project agreements provides a mechanism to prevent double recovery between the ICSID award and all or part of an earlier award of $908 million to an ExxonMobil affiliate, Mobil Cerro Negro, Ltd., against PdVSA and a PdVSA affiliate, PdVSA CN, in an arbitration under the rules of the International Chamber of Commerce.

On February 2, 2015, Venezuela filed a Request for Annulment of the ICSID award. On March 9, 2017, the ICSID Committee hearing the Request for Annulment issued a decision partially annulling the award of the Tribunal issued on October 9, 2014. The Committee affirmed the compensation due for the La Ceiba project and for export curtailments at the Cerro Negro project, but annulled the portion of the award relating to the Cerro Negro Project's expropriation ($1.4 billion) based on its determination that the prior Tribunal failed to adequately explain why the cap on damages in the indemnity owed by PdVSA did not affect or limit the amount owed for the expropriation of the Cerro Negro project. As a result, ExxonMobil retains an award for $260 million (including accrued interest). ExxonMobil reached an agreement with Venezuela for full payment of the $260 million and Venezuela has begun performing on it. The agreement does not impact ExxonMobil's ability to re-arbitrate the issue that was the basis for the annulment in a new ICSID arbitration proceeding.

The United States District Court for the Southern District of New York entered judgment on the ICSID award on October 10, 2014. Motions filed by Venezuela to vacate that judgment on procedural grounds and to modify the judgment by reducing the rate of interest to be paid on the ICSID award from the entry of the court’s judgment, until the date of payment, were denied on February 13, 2015, and March 4, 2015, respectively. On March 9, 2015, Venezuela filed a notice of appeal of the court’s actions on the two motions. On July 11, 2017, the United States Court of Appeals for the Second Circuit rendered its opinion overturning the District Court’s decision and vacating the judgment on the grounds that a different procedure should have been used to reduce the award to judgment. The Corporation is evaluating next steps.

A stay of the District Court’s judgment has continued pending the completion of the Second Circuit appeal. The net impact of these matters on the Corporation’s consolidated financial results cannot be reasonably estimated. Regardless, the Corporation does not expect the resolution to have a material effect upon the Corporation’s operations or financial condition.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

17. Pension and Other Postretirement Benefits

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2017	2016	2017	2016	2017	2016
			(percent)			
Weighted-average assumptions used to determine benefit obligations at December 31						
Discount rate	3.80	4.25	2.80	3.00	3.80	4.25
Long-term rate of compensation increase	5.75	5.75	4.30	4.00	5.75	5.75
			(millions of dollars)			
Change in benefit obligation						
Benefit obligation at January 1	19,960	19,583	25,196	25,117	7,800	8,282
Service cost	784	810	596	585	129	153
Interest cost	798	793	772	844	317	344
Actuarial loss/(gain)	733	250	250	1,409	231	(560)
Benefits paid *(1) (2)*	(2,964)	(1,476)	(1,291)	(1,228)	(543)	(537)
Foreign exchange rate changes	-	-	2,484	(1,520)	40	16
Amendments, divestments and other	(1)	-	(44)	(11)	126	102
Benefit obligation at December 31	19,310	19,960	27,963	25,196	8,100	7,800
Accumulated benefit obligation at December 31	15,557	16,245	25,557	22,867	-	-

(1) Benefit payments for funded and unfunded plans.

(2) For 2017 and 2016, other postretirement benefits paid are net of $16 million and $22 million of Medicare subsidy receipts, respectively.

For selection of the discount rate for U.S. plans, several sources of information are considered, including interest rate market indicators and the effective discount rate determined by use of a yield curve based on high-quality, noncallable bonds applied to the estimated cash outflows for benefit payments. For major non-U.S. plans, the discount rate is determined by using a spot yield curve of high-quality, local-currency-denominated bonds at an average maturity approximating that of the liabilities.

The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.5 percent in 2019 and subsequent years. A one-percentage-point increase in the health care cost trend rate would increase service and interest cost by $72 million and the postretirement benefit obligation by $696 million. A one-percentage-point decrease in the health care cost trend rate would decrease service and interest cost by $53 million and the postretirement benefit obligation by $536 million.

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2017	2016	2017	2016	2017	2016
			(millions of dollars)			
Change in plan assets						
Fair value at January 1	12,793	10,985	19,043	18,417	411	414
Actual return on plan assets	1,831	949	1,442	2,443	40	20
Foreign exchange rate changes	-	-	1,776	(1,452)	-	-
Company contribution	619	2,068	440	492	34	36
Benefits paid *(1)*	(2,461)	(1,209)	(902)	(857)	(58)	(59)
Other	-	-	(338)	-	-	-

Fair value at December 31	12,782	12,793	21,461	19,043	427	411

(1) Benefit payments for funded plans.

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2017	2016	2017	2016
	(millions of dollars)			
Assets in excess of/(less than) benefit obligation				
Balance at December 31				
Funded plans	(3,957)	(4,306)	413	212
Unfunded plans	(2,571)	(2,861)	(6,915)	(6,365)
Total	(6,528)	(7,167)	(6,502)	(6,153)

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

	Pension Benefits				Other Postretirement Benefits	
	U.S.		Non-U.S.			
	2017	2016	2017	2016	2017	2016
	(millions of dollars)					
Assets in excess of/(less than) benefit obligation						
Balance at December 31 *(1)*	(6,528)	(7,167)	(6,502)	(6,153)	(7,673)	(7,389)
Amounts recorded in the consolidated balance sheet consist of:						
Other assets	-	-	1,403	1,035	-	-
Current liabilities	(276)	(409)	(338)	(294)	(360)	(361)
Postretirement benefits reserves	(6,252)	(6,758)	(7,567)	(6,894)	(7,313)	(7,028)
Total recorded	(6,528)	(7,167)	(6,502)	(6,153)	(7,673)	(7,389)
Amounts recorded in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	3,982	5,354	5,586	5,629	1,595	1,468
Prior service cost	11	15	(143)	(123)	(397)	(430)
Total recorded in accumulated other comprehensive income	3,993	5,369	5,443	5,506	1,198	1,038

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

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

	Pension Benefits						Other Postretirement Benefits		
	U.S.			Non-U.S.					
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Weighted-average assumptions used to determine net periodic benefit cost for years ended December 31				(percent)					
Discount rate	4.25	4.25	4.00	3.00	3.60	3.10	4.25	4.25	4.00
Long-term rate of return on funded assets	6.50	6.50	7.00	5.20	5.25	5.90	6.50	6.50	7.00
Long-term rate of compensation increase	5.75	5.75	5.75	4.00	4.80	5.30	5.75	5.75	5.75
Components of net periodic benefit cost				(millions of dollars)					
Service cost	784	810	864	596	585	689	129	153	170
Interest cost	798	793	785	772	844	850	317	344	346
Expected return on plan assets	(775)	(726)	(830)	(1,000)	(927)	(1,094)	(24)	(25)	(28)
Amortization of actuarial loss/(gain)	438	492	544	476	536	730	96	153	206
Amortization of prior service cost	5	6	6	47	54	87	(33)	(30)	(24)
Net pension enhancement and curtailment/settlement cost	609	319	499	19	2	22	-	-	-
Net periodic benefit cost	1,859	1,694	1,868	910	1,094	1,284	485	595	670
Changes in amounts recorded in accumulated other comprehensive income:									
Net actuarial loss/(gain)	(324)	27	592	(191)	(156)	(1,375)	215	(555)	(589)
Amortization of actuarial (loss)/gain	(1,047)	(811)	(1,043)	(495)	(538)	(752)	(96)	(153)	(206)
Prior service cost/(credit)	-	-	-	111	32	(401)	-	-	(535)
Amortization of prior service (cost)/credit	(5)	(6)	(6)	(47)	(54)	(87)	33	30	24
Foreign exchange rate changes	-	-	-	559	(108)	(1,126)	8	5	(31)
Total recorded in other comprehensive income	(1,376)	(790)	(457)	(63)	(824)	(3,741)	160	(673)	(1,337)
Total recorded in net periodic benefit cost and other comprehensive income, before tax	483	904	1,411	847	270	(2,457)	645	(78)	(667)

Costs for defined contribution plans were $384 million, $399 million and $405 million in 2017, 2016 and 2015, respectively.

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

	Total Pension and Other Postretirement Benefits		
	2017	2016	2015
	(millions of dollars)		
(Charge)/credit to other comprehensive income, before tax			
U.S. pension	1,376	790	457
Non-U.S. pension	63	824	3,741
Other postretirement benefits	(160)	673	1,337
Total (charge)/credit to other comprehensive income, before tax	1,279	2,287	5,535
(Charge)/credit to income tax (see Note 4)	(290)	(692)	(1,810)
(Charge)/credit to investment in equity companies	(43)	(16)	81
(Charge)/credit to other comprehensive income including noncontrolling interests, after tax	946	1,579	3,806
Charge/(credit) to equity of noncontrolling interests	12	24	(202)
(Charge)/credit to other comprehensive income attributable to ExxonMobil	958	1,603	3,604

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

Studies are periodically conducted to establish the preferred target asset allocation percentages. The target asset allocation for the U.S. benefit plans and the major non-U.S. plans is 30 percent equity securities and 70 percent debt securities. The equity targets for the U.S. and certain non-U.S. plans include a small allocation to private equity partnerships that primarily focus on early-stage venture capital of 5 percent and 3 percent, respectively.

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

The 2017 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

	U.S. Pension					Non-U.S. Pension				
	Fair Value Measurement at December 31, 2017, Using:					Fair Value Measurement at December 31, 2017, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
					(millions of dollars)					
Asset category:										
Equity securities										
U.S.	-	-	-	1,665	1,665	-	-	-	2,967	2,967
Non-U.S.	-	-	-	1,570	1,570	111 *(2)*	-	-	2,903	3,014
Private equity	-	-	-	532	532	-	-	-	522	522
Debt securities										
Corporate	-	5,260 *(3)*	-	1	5,261	-	131 *(3)*	-	5,215	5,346
Government	-	3,604 *(3)*	-	2	3,606	237 *(4)*	32 *(3)*	-	9,056	9,325
Asset-backed	-	-	-	1	1	-	34 *(3)*	-	72	106
Cash	-	-	-	138	138	54	2 *(5)*	-	102	158
Total at fair value	-	8,864	-	3,909	12,773	402	199	-	20,837	21,438
Insurance contracts										
at contract value					9					23
Total plan assets					12,782					21,461

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

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

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

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

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

	Other Postretirement				
	Fair Value Measurement at December 31, 2017, Using:				
	Level 1	Level 2	Level 3	Net Asset Value *(1)*	Total
			(millions of dollars)		
Asset category:					
Equity securities					
U.S.	-	-	-	73	73
Non-U.S.	-	-	-	55	55
Private equity	-	-	-	-	-
Debt securities					
Corporate	-	99 *(2)*	-	-	99
Government	-	197 *(2)*	-	-	197
Asset-backed	-	1 *(2)*	-	-	1
Cash	-	-	-	2	2
Total at fair value	-	297	-	130	427

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The 2016 fair value of the benefit plan assets, including the level within the fair value hierarchy, is shown in the tables below:

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

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

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

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

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

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

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

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

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

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

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

	Pension Benefits			
	U.S.		Non-U.S.	
	2017	2016	2017	2016
	(millions of dollars)			
For funded pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	16,739	17,099	3,384	837
Accumulated benefit obligation	14,022	14,390	3,264	612
Fair value of plan assets	12,782	12,793	3,219	564
For unfunded pension plans:				
Projected benefit obligation	2,571	2,861	6,915	6,365
Accumulated benefit obligation	1,535	1,855	6,208	5,687

	Pension Benefits		Other Postretirement
	U.S.	Non-U.S.	Benefits
	(millions of dollars)		
Estimated 2018 amortization from accumulated other comprehensive income:			
Net actuarial loss/(gain) *(1)*	539	412	112
Prior service cost *(2)*	5	47	(40)

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

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

	Pension Benefits		Other Postretirement Benefits	
	U.S.	Non-U.S.	Gross	Medicare Subsidy Receipt
	(millions of dollars)			
Contributions expected in 2018	490	720	-	-
Benefit payments expected in:				
2018	1,364	1,183	459	25
2019	1,279	1,163	465	26
2020	1,267	1,197	469	28
2021	1,268	1,203	470	29
2022	1,285	1,220	468	30
2023 - 2027	6,355	6,162	2,329	174

18. Disclosures about Segments and Related Information

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

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

Earnings after income tax include transfers at estimated market prices.

In corporate and financing activities, interest revenue relates to interest earned on cash deposits and marketable securities. Interest expense includes non-debt-related interest expense of $136 million in 2017, $63 million in 2016 and $100 million in 2015.

	Upstream		Downstream		Chemical		Corporate and	Corporate
	U.S.	Non-U.S.	U.S.	Non-U.S.	U.S.	Non-U.S.	Financing	Total
				(millions of dollars)				
As of December 31, 2017								
Earnings after income tax	6,622	6,733	1,948	3,649	2,190	2,328	(3,760)	19,710
Earnings of equity companies included above	216	3,618	118	490	90	1,217	(369)	5,380
Sales and other operating revenue	9,349	14,508	61,695	122,881	11,035	17,659	35	237,162
Intersegment revenue	5,729	22,935	14,857	22,263	7,270	5,550	208	-
Depreciation and depletion expense	6,963	9,741	658	883	299	504	845	19,893
Interest revenue	-	-	-	-	-	-	36	36
Interest expense	87	29	1	6	-	-	478	601
Income tax expense (benefit)	(8,552)	5,463	(61)	934	362	664	16	(1,174)
Effect of U.S. tax reform - noncash	*(7,602)*	*480*	*(618)*	-	*(335)*	-	*2,133*	*(5,942)*
Additions to property, plant and equipment	9,761	8,617	769	1,551	1,330	2,019	854	24,901
Investments in equity companies	4,680	14,494	276	1,462	341	3,387	(286)	24,354
Total assets	89,048	155,822	18,172	34,294	13,363	21,133	16,859	348,691
As of December 31, 2016								
Earnings after income tax	(4,151)	4,347	1,094	3,107	1,876	2,739	(1,172)	7,840
Earnings of equity companies included above	53	3,359	58	404	111	1,188	(367)	4,806
Sales and other operating revenue *(1)*	7,552	12,278	52,630	102,756	9,944	15,447	21	200,628
Intersegment revenue	3,827	18,099	11,796	18,775	6,404	4,211	236	-
Depreciation and depletion expense	9,626	9,550	628	889	275	477	863	22,308
Interest revenue	-	-	-	-	-	-	30	30
Interest expense	17	29	1	8	-	-	398	453
Income tax expense (benefit)	(2,600)	1,818	396	951	693	609	(2,273)	(406)
Additions to property, plant and equipment	3,144	7,878	791	1,525	1,463	482	817	16,100
Investments in equity companies	4,917	11,364	111	1,255	158	3,247	(242)	20,810
Total assets	86,146	153,183	16,201	29,208	11,600	18,453	15,523	330,314
As of December 31, 2015								
Earnings after income tax	(1,079)	8,180	1,901	4,656	2,386	2,032	(1,926)	16,150
Earnings of equity companies included above	226	5,831	170	444	144	1,235	(406)	7,644
Sales and other operating revenue *(1)*	8,241	15,446	69,706	119,050	10,879	16,524	8	239,854
Intersegment revenue	4,344	20,839	12,440	22,166	7,442	5,168	274	-
Depreciation and depletion expense	5,301	9,227	664	1,003	375	654	824	18,048
Interest revenue	-	-	-	-	-	-	46	46
Interest expense	26	27	8	4	-	1	245	311
Income tax expense (benefit)	(879)	4,703	866	1,325	646	633	(1,879)	5,415
Additions to property, plant and equipment	6,915	14,561	916	1,477	1,865	629	1,112	27,475
Investments in equity companies	5,160	10,980	95	1,179	125	3,025	(227)	20,337
Total assets	93,648	155,316	16,498	29,808	10,174	18,236	13,078	336,758

(1) Sales and other operating revenue excludes previously reported sales-based taxes of $17,980 million for 2016 and $19,634 million for 2015. See Note 2: Accounting Changes.

Geographic

Sales and other operating revenue *(1)*	**2017**	**2016**	**2015**
		(millions of dollars)	
United States	82,079	70,126	88,826
Non-U.S.	155,083	130,502	151,028
Total	237,162	200,628	239,854
Significant non-U.S. revenue sources include:			
Canada	20,116	17,682	19,076
United Kingdom	16,611	15,452	20,605
Belgium	13,633	10,834	12,481
Singapore	11,589	9,919	10,632
Italy	11,476	9,715	11,220
France	11,235	9,487	10,631
Germany	8,484	7,899	8,447

(1) Sales and other operating revenue excludes previously reported sales-based taxes of $17,980 million for 2016 and $19,634 million for 2015. See Note 2: Accounting Changes.

Long-lived assets	**2017**	**2016**	**2015**
		(millions of dollars)	
United States	105,101	101,194	107,039
Non-U.S.	147,529	143,030	144,566
Total	252,630	244,224	251,605
Significant non-U.S. long-lived assets include:			
Canada	41,138	40,144	39,775
Australia	16,908	16,510	15,894
Singapore	11,292	9,769	9,681
Kazakhstan	10,121	10,325	9,705
Nigeria	9,734	11,314	12,222
Papua New Guinea	8,463	5,719	5,985
Angola	7,689	8,413	8,777
Russia	5,702	4,828	4,744

19. Income and Other Taxes

	2017			2016			2015		
	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total	U.S.	Non-U.S.	Total
					(millions of dollars)				
Income tax expense									
Federal and non-U.S.									
Current	577	6,633	7,210	(214)	4,056	3,842	-	7,126	7,126
Deferred - net	(9,075)	754	(8,321)	(2,801)	(1,422)	(4,223)	(1,166)	(571)	(1,737)
U.S. tax on non-U.S. operations	17	-	17	41	-	41	38	-	38
Total federal and non-U.S.	(8,481)	7,387	(1,094)	(2,974)	2,634	(340)	(1,128)	6,555	5,427
State	(80)	-	(80)	(66)	-	(66)	(12)	-	(12)
Total income tax expense	(8,561)	7,387	(1,174)	(3,040)	2,634	(406)	(1,140)	6,555	5,415
All other taxes and duties									
Other taxes and duties	3,330	26,774	30,104	3,209	25,811	29,020	3,206	27,103	30,309
Included in production and manufacturing expenses	1,107	747	1,854	1,052	808	1,860	1,157	828	1,985
Included in SG&A expenses	147	354	501	133	362	495	150	390	540
Total other taxes and duties	4,584	27,875	32,459	4,394	26,981	31,375	4,513	28,321	32,834
Total	(3,977)	35,262	31,285	1,354	29,615	30,969	3,373	34,876	38,249

Sales-based taxes were previously reported gross on the income statement and included in total taxes in the above table. See Note 2: Accounting Changes.

The above provisions for deferred income taxes include a net credit of $5,920 million in 2017, reflecting a $5,942 million credit related to U.S. tax reform and $22 million of other changes in tax laws and rates outside of the United States. Deferred income tax expense also includes net charges of $180 million in 2016 and $177 million in 2015 for the effect of changes in tax laws and rates.

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 guidance outlined in the SEC Staff Accounting Bulletin No. 118, the Corporation has included reasonable estimates of the income tax effects of the changes in tax law and tax rate. These include amounts for the remeasurement of the deferred income tax balance from the reduction in the corporate tax rate from 35 to 21 percent and the mandatory deemed repatriation of undistributed foreign earnings and profits. The Corporation has paid taxes on earnings outside the United States at tax rates on average above the historical U.S. rate of 35 percent. As a result, the deemed repatriation tax does not create a significant tax impact for ExxonMobil. The impact of tax law changes on the Corporation's financial statements could differ from its estimates due to further analysis of the new law, regulatory guidance, technical corrections legislation, or guidance under U.S. GAAP. If significant changes occur, the Corporation will provide updated information in connection with future regulatory filings.

The reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 35 percent for 2017, 2016 and 2015 is as follows:

	2017	2016	2015
		(millions of dollars)	
Income before income taxes			
United States	(754)	(5,832)	147
Non-U.S.	19,428	13,801	21,819
Total	18,674	7,969	21,966
Theoretical tax	6,536	2,789	7,688
Effect of equity method of accounting	(1,883)	(1,682)	(2,675)
Non-U.S. taxes in excess of/(less than) theoretical U.S. tax *(1)*	1,848	(582)	1,415
Effect of U.S. tax reform	(5,942)	-	-
Other *(2)*	(1,733)	(931)	(1,013)
Total income tax expense	(1,174)	(406)	5,415
Effective tax rate calculation			
Income taxes	(1,174)	(406)	5,415
ExxonMobil share of equity company income taxes	2,228	1,692	3,011
Total income taxes	1,054	1,286	8,426
Net income including noncontrolling interests	19,848	8,375	16,551
Total income before taxes	20,902	9,661	24,977
Effective income tax rate	5%	13%	34%

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

(2) 2017 includes an exploration tax benefit of $708 million. 2016 includes an exploration tax benefit of $198 million and benefits from an adjustment to a prior year tax position of $176 million.

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. Balances at December 31, 2017, reflect the deferred income tax effects from the enactment of the U.S. Tax Cuts and Jobs Act of 2017. The Corporation has elected to account for the tax on global intangible low-taxed income (GILTI) as a tax expense in the period in which it is incurred.

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

Tax effects of temporary differences for:	**2017**	**2016**
	(millions of dollars)	
Property, plant and equipment	36,559	46,744
Other liabilities	5,625	4,262
Total deferred tax liabilities	42,184	51,006
Pension and other postretirement benefits	(4,338)	(6,053)
Asset retirement obligations	(4,237)	(5,454)
Tax loss carryforwards	(6,767)	(5,472)
Other assets	(5,832)	(5,615)
Total deferred tax assets	(21,174)	(22,594)
Asset valuation allowances	2,565	1,509
Net deferred tax liabilities	23,575	29,921

In 2017, asset valuation allowances of $2,565 million increased by $1,056 million and included net provisions of $502 million, $402 million recorded in the acquisition of InterOil Corporation, and effects of foreign currency translation of $152 million.

Balance sheet classification	**2017**	**2016**
	(millions of dollars)	
Other assets, including intangibles, net	(3,318)	(4,120)
Deferred income tax liabilities	26,893	34,041
Net deferred tax liabilities	23,575	29,921

The Corporation’s earnings from subsidiary companies outside the United States were subject to the deemed repatriation required by the U.S. Tax Cuts and Jobs Act of 2017. Those amounts continue to be indefinitely reinvested and are retained to fund prior and future capital project expenditures. Deferred income taxes have not been recorded for certain additional future tax obligations, such as foreign withholding tax and state tax, as these earnings are expected to be indefinitely reinvested for the foreseeable future. As of December 31, 2017, it is not practicable to estimate the unrecognized deferred income tax liability.

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

Gross unrecognized tax benefits	2017	2016	2015
		(millions of dollars)	
Balance at January 1	9,468	9,396	8,986
Additions based on current year's tax positions	522	655	903
Additions for prior years' tax positions	523	534	496
Reductions for prior years' tax positions	(865)	(1,019)	(190)
Reductions due to lapse of the statute of limitations	(113)	(7)	(4)
Settlements with tax authorities	(782)	(70)	(725)
Foreign exchange effects/other	30	(21)	(70)
Balance at December 31	8,783	9,468	9,396

The gross unrecognized tax benefit balances shown above are predominantly related to tax positions that would reduce the Corporation’s effective tax rate if the positions are favorably resolved. Unfavorable resolution of these tax positions generally would not increase the effective tax rate. The 2017, 2016 and 2015 changes in unrecognized tax benefits did not have a material effect on the Corporation’s net income.

Resolution of these tax positions through negotiations with the relevant tax authorities or through litigation will take many years to complete. It is difficult to predict the timing of resolution for tax positions since such timing is not entirely within the control of the Corporation. In the United States, the Corporation has various ongoing U.S. federal income tax positions at issue with the Internal Revenue Service (IRS) for tax years beginning in 2006. The IRS has asserted penalties associated with several of those positions. The Corporation has not recognized the penalties as an expense because the Corporation does not expect the penalties to be sustained under applicable law. The Corporation has filed a refund suit for tax years 2006-2009 in a U.S. federal district court with respect to the positions at issue for those years. Unfavorable resolution of all positions at issue with the IRS would not have a materially adverse effect on the Corporation’s net income or liquidity.

It is reasonably possible that the total amount of unrecognized tax benefits could increase or decrease by 10 percent in the next 12 months with no material impact on the Corporation's net income.

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

Country of Operation	Open Tax Years
Abu Dhabi	2014 - 2017
Angola	2016 - 2017
Australia	2008 - 2017
Belgium	2015 - 2017
Canada	1998 - 2017
Equatorial Guinea	2007 - 2017
Indonesia	2007 - 2017
Iraq	2012 - 2017
Malaysia	2009 - 2017
Nigeria	2006 - 2017
Norway	2007 - 2017
Papua New Guinea	2008 - 2017
Russia	2015 - 2017
United Kingdom	2015 - 2017
United States	2006 - 2017

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

The Corporation incurred $36 million, $4 million and $39 million in interest expense on income tax reserves in 2017, 2016 and 2015, respectively. The related interest payable balances were $168 million and $191 million at December 31, 2017, and 2016, respectively.

20. Acquisitions

InterOil Corporation

On February 22, 2017, the Corporation completed the acquisition of InterOil Corporation (IOC) for $2.7 billion. The IOC acquisition was mostly unproved properties in Papua New Guinea. Consideration included 28 million shares of Exxon Mobil Corporation common stock having a value on the acquisition date of $2.2 billion, a Contingent Resource Payment (CRP) with a fair value of $0.3 billion and cash of $0.2 billion. The CRP provided IOC shareholders $7.07 per share in cash for each incremental independently certified Trillion Cubic Feet Equivalent (TCFE) of resources above 6.2 TCFE, up to 11.0 TCFE. IOC's assets include a contingent receivable related to the same resource base for volumes in excess of 3.5 TCFE at amounts ranging from $0.24 - $0.40 per thousand cubic feet equivalent. The fair value of the contingent receivable was $1.1 billion at the acquisition date. Fair values of contingent amounts were based on assumptions about the outcome of the resource certification, future business plans and appropriate discount rates.

On September 6, 2017, the resource certification was finalized triggering both payment of the CRP to former IOC shareholders and receipt of the current portion of the contingent receivable. The earnings impact from settlement of the CRP and the related contingent receivable was not material.

Permian Basin Properties

On February 28, 2017, the Corporation completed the acquisition for $6.2 billion of a number of companies from the Bass family in Fort Worth, Texas, that indirectly own mostly unproved oil and gas properties in the Permian Basin. Consideration included 68 million shares of Exxon Mobil Corporation common stock having a value on the acquisition date of $5.5 billion, together with additional contingent cash payments tied to future drilling and completion activities (up to a maximum of $1.02 billion). Fair value of the contingent payment was $0.7 billion as of the acquisition date and is expected to be paid beginning in 2020 and ending no later than 2032 commensurate with development of the resource. Fair value of the contingent payment was based on assumptions including drilling and completion activities, appropriate discount rates and tax rates.

The fair value of the contingent payment is adjusted each quarter. The earnings impact from these adjustments was not material.

Below is a summary of the net assets acquired for each acquisition.

	IOC	**Permian**
	(billions of dollars)	
Current assets	0.6	-
Property, plant and equipment	2.9	6.3
Other	0.6	-
Total assets	4.1	6.3
Current liabilities	0.5	-
Long-term liabilities	0.9	0.1
Total liabilities	1.4	0.1
Net assets acquired	**2.7**	**6.2**

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

The results of operations for producing activities shown below do not include earnings from other activities that ExxonMobil includes in the Upstream function, such as oil and gas transportation operations, LNG liquefaction and transportation operations, coal and power operations, technical service agreements, other nonoperating activities and adjustments for noncontrolling interests. These excluded amounts for both consolidated and equity companies totaled $1,402 million in 2017, $719 million in 2016, and $831 million in 2015. Oil sands mining operations are included in the results of operations in accordance with Securities and Exchange Commission and Financial Accounting Standards Board rules.

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
			(millions of dollars)				
Consolidated Subsidiaries							
2017 - Revenue							
Sales to third parties	5,223	1,911	3,652	993	2,239	2,244	16,262
Transfers	3,852	3,462	1,631	7,771	6,035	689	23,440
	9,075	5,373	5,283	8,764	8,274	2,933	39,702
Production costs excluding taxes	3,730	3,833	1,576	2,064	1,618	626	13,447
Exploration expenses	162	647	94	311	494	82	1,790
Depreciation and depletion	6,689	2,005	1,055	2,957	1,782	913	15,401
Taxes other than income	684	97	146	559	811	311	2,608
Related income tax	(8,066)	(180)	1,717	1,911	2,148	316	(2,154)
Results of producing activities for consolidated subsidiaries	5,876	(1,029)	695	962	1,421	685	8,610
Equity Companies							
2017 - Revenue							
Sales to third parties	585	-	1,636	-	8,926	-	11,147
Transfers	443	-	10	-	638	-	1,091
	1,028	-	1,646	-	9,564	-	12,238
Production costs excluding taxes	523	-	418	-	336	-	1,277
Exploration expenses	1	-	13	-	878	-	892
Depreciation and depletion	320	-	166	-	477	-	963
Taxes other than income	33	-	679	-	2,997	-	3,709
Related income tax	-	-	130	-	1,924	-	2,054
Results of producing activities for equity companies	151	-	240	-	2,952	-	3,343
Total results of operations	6,027	(1,029)	935	962	4,373	685	11,953

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2016 - Revenue							
Sales to third parties	4,424	1,511	2,921	705	1,826	1,273	12,660
Transfers	2,323	2,652	1,568	6,498	4,638	578	18,257
	6,747	4,163	4,489	7,203	6,464	1,851	30,917
Production costs excluding taxes	3,590	3,651	1,794	2,216	1,331	531	13,113
Exploration expenses	220	572	94	292	205	84	1,467
Depreciation and depletion	9,334	1,601	1,678	3,573	1,613	532	18,331
Taxes other than income	491	165	139	762	621	209	2,387
Related income tax	(2,543)	(688)	546	(149)	1,767	167	(900)
Results of producing activities for consolidated subsidiaries	(4,345)	(1,138)	238	509	927	328	(3,481)
Equity Companies							
2016 - Revenue							
Sales to third parties	506	-	1,677	-	7,208	-	9,391
Transfers	344	-	9	-	418	-	771
	850	-	1,686	-	7,626	-	10,162
Production costs excluding taxes	527	-	529	-	504	-	1,560
Exploration expenses	-	-	36	-	21	-	57
Depreciation and depletion	301	-	143	-	437	-	881
Taxes other than income	31	-	661	-	2,456	-	3,148
Related income tax	-	-	86	-	1,472	-	1,558
Results of producing activities for equity companies	(9)	-	231	-	2,736	-	2,958
Total results of operations	(4,354)	(1,138)	469	509	3,663	328	(523)
Consolidated Subsidiaries							
2015 - Revenue							
Sales to third parties	4,830	1,756	3,933	1,275	2,651	1,408	15,853
Transfers	2,557	2,858	2,024	8,135	4,490	608	20,672
	7,387	4,614	5,957	9,410	7,141	2,016	36,525
Production costs excluding taxes	4,252	3,690	2,232	1,993	1,562	527	14,256
Exploration expenses	182	473	187	319	254	108	1,523
Depreciation and depletion	5,054	1,315	1,641	3,874	1,569	392	13,845
Taxes other than income	630	111	200	734	706	171	2,552
Related income tax	(976)	(79)	807	1,556	2,117	238	3,663
Results of producing activities for consolidated subsidiaries	(1,755)	(896)	890	934	933	580	686
Equity Companies							
2015 - Revenue							
Sales to third parties	608	-	2,723	-	11,174	-	14,505
Transfers	459	-	31	-	379	-	869
	1,067	-	2,754	-	11,553	-	15,374
Production costs excluding taxes	554	-	565	-	422	-	1,541
Exploration expenses	12	-	21	-	18	-	51
Depreciation and depletion	271	-	146	-	457	-	874

Taxes other than income	47	-	1,258	-	3,197	-	4,502
Related income tax	-	-	263	-	2,559	-	2,822
Results of producing activities for equity companies	183	-	501	-	4,900	-	5,584
Total results of operations	(1,572)	(896)	1,391	934	5,833	580	6,270

Oil and Gas Exploration and Production Costs

The amounts shown for net capitalized costs of consolidated subsidiaries are $15,292 million less at year-end 2017 and $15,239 million less at year-end 2016 than the amounts reported as investments in property, plant and equipment for the Upstream in Note 9. This is due to the exclusion from capitalized costs of certain transportation and research assets and assets relating to LNG operations. Assets related to oil sands and oil shale mining operations are included in the capitalized costs in accordance with Financial Accounting Standards Board rules.

Capitalized Costs		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
Consolidated Subsidiaries								
As of December 31, 2017								
Property (acreage) costs	- Proved	17,380	2,560	139	982	2,624	778	24,463
	- Unproved	27,051	5,238	62	196	179	2,701	35,427
Total property costs		44,431	7,798	201	1,178	2,803	3,479	59,890
Producing assets		94,253	48,951	30,908	52,137	37,808	14,564	278,621
Incomplete construction		2,016	1,484	1,173	4,294	5,499	1,440	15,906
Total capitalized costs		140,700	58,233	32,282	57,609	46,110	19,483	354,417
Accumulated depreciation and depletion		61,041	18,780	27,040	37,924	18,354	6,279	169,418
Net capitalized costs for consolidated subsidiaries		79,659	39,453	5,242	19,685	27,756	13,204	184,999
Equity Companies								
As of December 31, 2017								
Property (acreage) costs	- Proved	78	-	4	309	-	-	391
	- Unproved	11	-	-	3,111	59	-	3,181
Total property costs		89	-	4	3,420	59	-	3,572
Producing assets		6,410	-	5,678	-	9,824	-	21,912
Incomplete construction		98	-	45	516	4,611	-	5,270
Total capitalized costs		6,597	-	5,727	3,936	14,494	-	30,754
Accumulated depreciation and depletion		2,722	-	4,625	-	6,519	-	13,866
Net capitalized costs for equity companies		3,875	-	1,102	3,936	7,975	-	16,888
Consolidated Subsidiaries								
As of December 31, 2016								
Property (acreage) costs	- Proved	16,075	2,339	134	929	1,739	736	21,952
	- Unproved	22,747	4,030	25	291	269	115	27,477
Total property costs		38,822	6,369	159	1,220	2,008	851	49,429
Producing assets		91,651	40,291	33,811	51,307	34,690	11,730	263,480
Incomplete construction		2,099	6,154	1,403	4,495	8,377	2,827	25,355
Total capitalized costs		132,572	52,814	35,373	57,022	45,075	15,408	338,264
Accumulated depreciation and depletion		55,924	15,740	28,291	35,085	17,475	5,084	157,599
Net capitalized costs for consolidated subsidiaries		76,648	37,074	7,082	21,937	27,600	10,324	180,665
Equity Companies								
As of December 31, 2016								
Property (acreage) costs	- Proved	77	-	3	-	-	-	80
	- Unproved	12	-	-	-	59	-	71
Total property costs		89	-	3	-	59	-	151
Producing assets		6,326	-	5,043	-	8,646	-	20,015
Incomplete construction		109	-	40	-	4,791	-	4,940

Total capitalized costs	6,524	-	5,086	-	13,496	-	25,106
Accumulated depreciation and depletion	2,417	-	3,987	-	6,013	-	12,417
Net capitalized costs for equity companies	4,107	-	1,099	-	7,483	-	12,689

Oil and Gas Exploration and Production Costs (continued)

The amounts reported as costs incurred include both capitalized costs and costs charged to expense during the year. Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligation resulting from changes in cost estimates or abandonment date. Total consolidated costs incurred in 2017 were $19,644 million, up $8,269 million from 2016, due primarily to acquisitions of unproved properties, partially offset by lower development costs including lower asset retirement obligation cost estimates mainly in the North Sea. In 2016 costs were $11,375 million, down $10,512 million from 2015, due primarily to lower development costs. Total equity company costs incurred in 2017 were $6,008 million, up $4,602 million from 2016, due primarily to acquisition of unproved properties.

Costs Incurred in Property Acquisitions, Exploration and Development Activities		**United States**	**Canada/ Other Americas**	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)				
During 2017								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	88	5	-	50	583	-	726
	- Unproved	6,167	1,004	35	70	-	2,601	9,877
Exploration costs		190	702	109	373	224	509	2,107
Development costs		3,752	877	(39)	628	1,450	266	6,934
Total costs incurred for consolidated subsidiaries		10,197	2,588	105	1,121	2,257	3,376	19,644
Equity Companies								
Property acquisition costs	- Proved	-	-	-	309	-	-	309
	- Unproved	-	-	-	3,111	-	-	3,111
Exploration costs		1	-	3	323	90	-	417
Development costs		137	-	41	192	1,801	-	2,171
Total costs incurred for equity companies		138	-	44	3,935	1,891	-	6,008
During 2016								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	1	1	-	-	71	-	73
	- Unproved	170	27	-	-	-	-	197
Exploration costs		145	689	156	321	187	133	1,631
Development costs		3,054	1,396	538	1,866	2,214	406	9,474
Total costs incurred for consolidated subsidiaries		3,370	2,113	694	2,187	2,472	539	11,375
Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	-	-	-
Exploration costs		1	-	36	-	32	-	69
Development costs		106	-	88	-	1,143	-	1,337
Total costs incurred for equity companies		107	-	124	-	1,175	-	1,406
During 2015								
Consolidated Subsidiaries								
Property acquisition costs	- Proved	6	-	-	-	31	-	37
	- Unproved	305	39	-	93	1	2	440
Exploration costs		195	621	411	425	405	157	2,214
Development costs		6,774	3,764	1,439	3,149	3,068	1,002	19,196
Total costs incurred for consolidated subsidiaries		7,280	4,424	1,850	3,667	3,505	1,161	21,887

Equity Companies								
Property acquisition costs	- Proved	-	-	-	-	-	-	-
	- Unproved	-	-	-	-	-	-	-
Exploration costs		9	-	41	-	(19)	-	31
Development costs		411	-	143	-	879	-	1,433
Total costs incurred for equity companies		420	-	184	-	860	-	1,464

Oil and Gas Reserves

The following information describes changes during the years and balances of proved oil and gas reserves at year-end 2015, 2016, and 2017.

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

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

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

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

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

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

Reserves reported under production sharing and other nonconcessionary agreements are based on the economic interest as defined by the specific fiscal terms in the agreement. The production and reserves that we report for these types of arrangements typically vary inversely with oil and natural gas price changes. As oil and natural gas prices increase, the cash flow and value received by the company increase; however, the production volumes and reserves required to achieve this value will typically be lower because of the higher prices. When prices decrease, the opposite effect generally occurs. The percentage of total liquids and natural gas proved reserves (consolidated subsidiaries plus equity companies) at year-end 2017 that were associated with production sharing contract arrangements was 12 percent of liquids, 10 percent of natural gas and 11 percent on an oil-equivalent basis (natural gas converted to oil-equivalent at 6 billion cubic feet = 1 million barrels).

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

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

The changes between 2017 year-end proved reserves and 2016 year-end proved reserves primarily reflect extensions/ discoveries in the United States, Guyana, and the United Arab Emirates, as well as purchases in the Permian Basin and offshore Area 4 in Mozambique, along with upward revisions to North America natural gas, liquids in the United Arab Emirates, and bitumen at Kearl and Cold Lake. Downward revisions are reflected in Europe for the Groningen gas field.

The downward revisions in 2016, as the result of very low prices during 2016, include the entire 3.5 billion barrels of bitumen at Kearl. In addition, 0.8 billion barrels of oil equivalent across the remainder of North America no longer qualified as proved reserves at year-end 2016 mainly due to the acceleration of the projected end-of-field-life.

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

	Crude Oil							Natural Gas Liquids *(1)*	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
							(millions of barrels)				
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2015	2,108	282	199	1,102	2,132	141	5,964	1,092	4,233	534	11,823
Revisions	(150)	(10)	46	48	123	(4)	53	(95)	433	68	459
Improved recovery	-	-	2	-	-	-	2	-	-	-	2
Purchases	161	3	1	-	-	-	165	46	-	-	211
Sales	(9)	-	(1)	-	(2)	-	(12)	(1)	-	-	(13)
Extensions/discoveries	387	2	-	-	698	-	1,087	101	-	-	1,188
Production	(119)	(17)	(63)	(187)	(126)	(12)	(524)	(65)	(106)	(21)	(716)
December 31, 2015	2,378	260	184	963	2,825	125	6,735	1,078	4,560	581	12,954
Proportional interest in proved reserves of equity companies											
January 1, 2015	328	-	27	-	1,100	-	1,455	435	-	-	1,890
Revisions	(52)	-	(1)	-	65	-	12	5	-	-	17
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(22)	-	(1)	-	(88)	-	(111)	(26)	-	-	(137)
December 31, 2015	254	-	25	-	1,077	-	1,356	414	-	-	1,770
Total liquids proved reserves at December 31, 2015	2,632	260	209	963	3,902	125	8,091	1,492	4,560	581	14,724
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2016	2,378	260	184	963	2,825	125	6,735	1,078	4,560	581	12,954
Revisions	(307)	3	43	49	73	9	(130)	47	(3,748)	8	(3,823)
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	79	-	-	-	-	-	79	32	-	-	111
Sales	(15)	(5)	(3)	-	-	-	(23)	(5)	-	-	(28)
Extensions/discoveries	173	3	12	-	-	-	188	66	-	-	254
Production	(127)	(20)	(63)	(168)	(140)	(13)	(531)	(64)	(111)	(25)	(731)
December 31, 2016	2,181	241	173	844	2,758	121	6,318	1,154	701	564	8,737
Proportional interest in proved reserves of equity companies											
January 1, 2016	254	-	25	-	1,077	-	1,356	414	-	-	1,770
Revisions	3	-	(7)	-	191	-	187	(5)	-	-	182
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(21)	-	(1)	-	(85)	-	(107)	(25)	-	-	(132)

December 31, 2016	236	-	17	-	1,183	-	1,436	384	-	-	1,820
Total liquids proved reserves at December 31, 2016	2,417	241	190	844	3,941	121	7,754	1,538	701	564	10,557

(See footnote on next page)

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

	Crude Oil							Natural Gas Liquids (1)	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
	(millions of barrels)										
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2017	2,181	241	173	844	2,758	121	6,318	1,154	701	564	8,737
Revisions	70	19	43	30	490	2	654	(49)	416	(70)	951
Improved recovery	-	-	-	2	-	-	2	-	6	-	8
Purchases	428	5	-	-	-	-	433	164	-	-	597
Sales	(10)	-	(43)	-	-	-	(53)	(2)	-	-	(55)
Extensions/discoveries	158	161	-	3	384	-	706	58	-	-	764
Production	(132)	(16)	(54)	(150)	(136)	(13)	(501)	(67)	(111)	(21)	(700)
December 31, 2017	2,695	410	119	729	3,496	110	7,559	1,258	1,012	473	10,302
Proportional interest in proved reserves of equity companies											
January 1, 2017	236	-	17	-	1,183	-	1,436	384	-	-	1,820
Revisions	29	-	(1)	-	-	-	28	4	-	-	32
Improved recovery	-	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	6	-	-	6	-	-	-	6
Sales	-	-	-	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-	-	-	-
Production	(20)	-	(1)	-	(86)	-	(107)	(24)	-	-	(131)
December 31, 2017	245	-	15	6	1,097	-	1,363	364	-	-	1,727
Total liquids proved reserves at December 31, 2017	2,940	410	134	735	4,593	110	8,922	1,622	1,012	473	12,029

(1) Includes total proved reserves attributable to Imperial Oil Limited of 7 million barrels in 2015, 7 million barrels in 2016 and 10 million barrels in 2017, as well as proved developed reserves of 4 million barrels in 2015, 4 million barrels in 2016 and 3 million barrels in 2017, and in addition, proved undeveloped reserves of 3 million barrels in 2015, 3 million barrels in 2016 and 7 million barrels in 2017, in which there is a 30.4 percent noncontrolling interest.

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ Other Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ Other Amer. *(2)*	Canada/ Other Amer. *(3)*	Total
					(millions of barrels)					
Proved developed reserves, as of December 31, 2015										
Consolidated subsidiaries	1,427	101	192	900	1,707	107	4,434	4,108	581	9,123
Equity companies	228	-	25	-	1,151	-	1,404	-	-	1,404
Proved undeveloped reserves, as of December 31, 2015										
Consolidated subsidiaries	1,619	174	34	230	1,239	83	3,379	452	-	3,831
Equity companies	39	-	-	-	327	-	366	-	-	366
Total liquids proved reserves at December 31, 2015	3,313	275	251	1,130	4,424	190	9,583	4,560	581	14,724
Proved developed reserves, as of December 31, 2016										
Consolidated subsidiaries	1,317	87	175	836	1,858	105	4,378	436	564	5,378
Equity companies	210	-	11	-	1,114	-	1,335	-	-	1,335
Proved undeveloped reserves, as of December 31, 2016										
Consolidated subsidiaries	1,626	169	31	169	1,025	74	3,094	265	-	3,359
Equity companies	36	-	6	-	443	-	485	-	-	485
Total liquids proved reserves at December 31, 2016	3,189	256	223	1,005	4,440	179	9,292	701	564	10,557
Proved developed reserves, as of December 31, 2017										
Consolidated subsidiaries	1,489	92	119	676	2,182	131	4,689	657	473	5,819
Equity companies	208	-	14	-	1,019	-	1,241	-	-	1,241
Proved undeveloped reserves, as of December 31, 2017										
Consolidated subsidiaries	2,167	337	30	137	1,426	31	4,128	355	-	4,483
Equity companies	48	-	1	6	431	-	486	-	-	486
Total liquids proved reserves at December 31, 2017	3,912	429	164	819	5,058	162	10,544 *(4)*	1,012	473	12,029

(1) Includes total proved reserves attributable to Imperial Oil Limited of 34 million barrels in 2015, 35 million barrels in 2016 and 45 million barrels in 2017, as well as proved developed reserves of 23 million barrels in 2015, 19 million barrels in 2016 and 10 million barrels in 2017, and in addition, proved undeveloped reserves of 11 million barrels in 2015, 16 million barrels in 2016 and 35 million barrels in 2017, in which there is a 30.4 percent noncontrolling interest.

(2) Includes total proved reserves attributable to Imperial Oil Limited of 3,515 million barrels in 2015, 701 million barrels in 2016 and 946 million barrels in 2017, as well as proved developed reserves of 3,063 million barrels in 2015, 436 million barrels in 2016 and 591 million barrels in 2017, and in addition, proved undeveloped reserves

of 452 million barrels in 2015, 265 million barrels in 2016 and 355 million barrels in 2017, in which there is a 30.4 percent noncontrolling interest.

(3) *Includes total proved reserves attributable to Imperial Oil Limited of 581 million barrels in 2015, 564 million barrels in 2016 and 473 million barrels in 2017, as well as proved developed reserves of 581 million barrels in 2015, 564 million barrels in 2016 and 473 million barrels in 2017, in which there is a 30.4 percent noncontrolling interest.*

(4) *See previous pages for natural gas liquids proved reserves attributable to consolidated subsidiaries and equity companies. For additional information on natural gas liquids proved reserves see Item 2. Properties in ExxonMobil's 2017 Form 10-K.*

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							Oil-Equivalent
	United States	Canada/ Other Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Total All Products *(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2015	25,987	1,226	2,383	811	5,460	7,276	43,143	19,013
Revisions	(6,693)	(45)	63	25	303	23	(6,324)	(595)
Improved recovery	-	-	-	-	-	-	-	2
Purchases	182	29	-	-	-	-	211	246
Sales	(9)	(5)	(56)	-	(89)	-	(159)	(39)
Extensions/discoveries	1,167	34	-	-	102	-	1,303	1,405
Production	(1,254)	(112)	(434)	(43)	(447)	(258)	(2,548)	(1,140)
December 31, 2015	19,380	1,127	1,956	793	5,329	7,041	35,626	18,892
Proportional interest in proved reserves of equity companies								
January 1, 2015	272	-	8,418	-	17,505	-	26,195	6,256
Revisions	(38)	-	(83)	-	86	-	(35)	11
Improved recovery	-	-	-	-	-	-	-	-
Purchases	1	-	-	-	-	-	1	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-
Production	(15)	-	(432)	-	(1,130)	-	(1,577)	(400)
December 31, 2015	220	-	7,903	-	16,461	-	24,584	5,867
Total proved reserves at December 31, 2015	19,600	1,127	9,859	793	21,790	7,041	60,210	24,759
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2016	19,380	1,127	1,956	793	5,329	7,041	35,626	18,892
Revisions	(1,630)	(102)	126	21	(16)	658	(943)	(3,980)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	148	-	-	-	-	-	148	135
Sales	(45)	(12)	(2)	-	-	-	(59)	(38)
Extensions/discoveries	1,156	34	6	-	-	-	1,196	453
Production	(1,223)	(107)	(427)	(43)	(392)	(342)	(2,534)	(1,153)
December 31, 2016	17,786	940	1,659	771	4,921	7,357	33,434	14,309
Proportional interest in proved reserves of equity companies								
January 1, 2016	220	-	7,903	-	16,461	-	24,584	5,867
Revisions	4	-	114	-	(183)	-	(65)	171
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	5	-	-	-	5	1
Production	(13)	-	(398)	-	(1,044)	-	(1,455)	(374)
December 31, 2016	211	-	7,624	-	15,234	-	23,069	5,665
Total proved reserves at December 31, 2016	17,997	940	9,283	771	20,155	7,357	56,503	19,974

(See footnotes on next page)

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ Other Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2017	17,786	940	1,659	771	4,921	7,357	33,434	14,309
Revisions	649	206	134	(135)	(214)	33	673	1,063
Improved recovery	-	1	-	-	-	-	1	8
Purchases	982	56	-	-	-	-	1,038	771
Sales	(172)	(1)	(17)	-	-	-	(190)	(87)
Extensions/discoveries	956	269	-	-	13	-	1,238	970
Production	(1,168)	(99)	(408)	(41)	(380)	(496)	(2,592)	(1,131)
December 31, 2017	19,033	1,372	1,368	595	4,340	6,894	33,602	15,903
Proportional interest in proved reserves of equity companies								
January 1, 2017	211	-	7,624	-	15,234	-	23,069	5,665
Revisions	25	-	(1,129)	-	86	-	(1,018)	(138)
Improved recovery	-	-	-	-	-	-	-	-
Purchases	-	-	-	914	-	-	914	158
Sales	-	-	-	-	-	-	-	-
Extensions/discoveries	-	-	-	-	-	-	-	-
Production	(13)	-	(331)	-	(1,072)	-	(1,416)	(367)
December 31, 2017	223	-	6,164	914	14,248	-	21,549	5,318
Total proved reserves at December 31, 2017	19,256	1,372	7,532	1,509	18,588	6,894	55,151	21,221

(1) Includes total proved reserves attributable to Imperial Oil Limited of 583 billion cubic feet in 2015, 495 billion cubic feet in 2016 and 641 billion cubic feet in 2017, as well as proved developed reserves of 283 billion cubic feet in 2015, 263 billion cubic feet in 2016 and 282 billion cubic feet in 2017, and in addition, proved undeveloped reserves of 300 billion cubic feet in 2015, 232 billion cubic feet in 2016 and 359 billion cubic feet in 2017, in which there is a 30.4 percent noncontrolling interest.

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

	Natural Gas							
	United States	Canada/ Other Amer. *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products** ***(2)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Proved developed reserves, as of December 31, 2015								
Consolidated subsidiaries	13,353	552	1,593	750	4,917	1,962	23,127	12,977
Equity companies	156	-	6,146	-	15,233	-	21,535	4,993
Proved undeveloped reserves, as of December 31, 2015								
Consolidated subsidiaries	6,027	575	363	43	412	5,079	12,499	5,915
Equity companies	64	-	1,757	-	1,228	-	3,049	874
Total proved reserves at December 31, 2015	19,600	1,127	9,859	793	21,790	7,041	60,210	24,759
Proved developed reserves, as of December 31, 2016								
Consolidated subsidiaries	11,927	478	1,473	728	4,532	3,071	22,209	9,079
Equity companies	144	-	5,804	-	14,067	-	20,015	4,671
Proved undeveloped reserves, as of December 31, 2016								
Consolidated subsidiaries	5,859	462	186	43	389	4,286	11,225	5,230
Equity companies	67	-	1,820	-	1,167	-	3,054	994
Total proved reserves at December 31, 2016	17,997	940	9,283	771	20,155	7,357	56,503	19,974
Proved developed reserves, as of December 31, 2017								
Consolidated subsidiaries	12,649	512	1,231	584	4,030	4,420	23,426	9,724
Equity companies	154	-	4,899	-	12,898	-	17,951	4,232
Proved undeveloped reserves, as of December 31, 2017								
Consolidated subsidiaries	6,384	860	137	11	310	2,474	10,176	6,179
Equity companies	69	-	1,265	914	1,350	-	3,598	1,086
Total proved reserves at December 31, 2017	19,256	1,372	7,532	1,509	18,588	6,894	55,151	21,221

(See footnotes on previous page)

Standardized Measure of Discounted Future Cash Flows

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

Standardized Measure of Discounted Future Cash Flows	**United States**	**Canada/ Other Americas** *(1)*	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2015							
Future cash inflows from sales of oil and gas	144,910	176,452	23,330	57,702	156,378	29,535	588,307
Future production costs	82,678	115,285	8,735	17,114	50,745	8,889	283,446
Future development costs	35,016	36,923	11,332	11,170	15,371	8,237	118,049
Future income tax expenses	5,950	3,042	1,780	14,018	62,353	5,012	92,155
Future net cash flows	21,266	21,202	1,483	15,400	27,909	7,397	94,657
Effect of discounting net cash flows at 10%	13,336	13,415	(945)	5,226	17,396	3,454	51,882
Discounted future net cash flows	7,930	7,787	2,428	10,174	10,513	3,943	42,775
Equity Companies							
As of December 31, 2015							
Future cash inflows from sales of oil and gas	13,065	-	49,061	-	143,692	-	205,818
Future production costs	6,137	-	35,409	-	57,080	-	98,626
Future development costs	2,903	-	2,190	-	12,796	-	17,889
Future income tax expenses	-	-	4,027	-	24,855	-	28,882
Future net cash flows	4,025	-	7,435	-	48,961	-	60,421
Effect of discounting net cash flows at 10%	1,936	-	4,287	-	26,171	-	32,394
Discounted future net cash flows	2,089	-	3,148	-	22,790	-	28,027
Total consolidated and equity interests in standardized measure of discounted future net cash flows	10,019	7,787	5,576	10,174	33,303	3,943	70,802

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

Standardized Measure of Discounted Future Cash Flows (continued)	**United States**	**Canada/ Other Americas** *(1)*	**Europe**	**Africa**	**Asia**	**Australia/ Oceania**	**Total**
			(millions of dollars)				
Consolidated Subsidiaries							
As of December 31, 2016							
Future cash inflows from sales of oil and gas	118,283	50,243	15,487	40,734	118,997	28,877	372,621
Future production costs	65,585	29,798	5,362	14,447	38,727	7,643	161,562
Future development costs	31,744	11,735	9,235	8,833	13,088	8,177	82,812
Future income tax expenses	2,223	1,052	178	8,025	44,641	2,316	58,435
Future net cash flows	18,731	7,658	712	9,429	22,541	10,741	69,812
Effect of discounting net cash flows at 10%	11,039	3,443	(1,014)	2,790	12,848	5,556	34,662
Discounted future net cash flows	7,692	4,215	1,726	6,639	9,693	5,185	35,150
Equity Companies							
As of December 31, 2016							
Future cash inflows from sales of oil and gas	9,551	-	32,121	-	104,700	-	146,372
Future production costs	5,289	-	21,342	-	41,563	-	68,194
Future development costs	2,948	-	2,048	-	12,656	-	17,652
Future income tax expenses	-	-	2,206	-	16,622	-	18,828
Future net cash flows	1,314	-	6,525	-	33,859	-	41,698
Effect of discounting net cash flows at 10%	393	-	4,158	-	18,946	-	23,497
Discounted future net cash flows	921	-	2,367	-	14,913	-	18,201
Total consolidated and equity interests in standardized measure of discounted future net cash flows	8,613	4,215	4,093	6,639	24,606	5,185	53,351
Consolidated Subsidiaries							
As of December 31, 2017							
Future cash inflows from sales of oil and gas	186,126	78,870	14,794	43,223	191,254	40,814	555,081
Future production costs	78,980	42,280	4,424	14,049	53,723	8,424	201,880
Future development costs	39,996	18,150	7,480	8,897	15,156	7,951	97,630
Future income tax expenses	12,879	4,527	2,790	8,818	90,614	6,017	125,645
Future net cash flows	54,271	13,913	100	11,459	31,761	18,422	129,926
Effect of discounting net cash flows at 10%	30,574	6,158	(1,255)	2,996	17,511	8,741	64,725
Discounted future net cash flows	23,697	7,755	1,355	8,463	14,250	9,681	65,201
Equity Companies							
As of December 31, 2017							
Future cash inflows from sales of oil and gas	12,643	-	28,557	2,366	127,364	-	170,930
Future production costs	5,927	-	21,120	247	48,300	-	75,594
Future development costs	3,012	-	1,913	417	11,825	-	17,167
Future income tax expenses	-	-	1,683	514	22,396	-	24,593
Future net cash flows	3,704	-	3,841	1,188	44,843	-	53,576

Effect of discounting net cash flows at 10%	1,668	-	2,116	1,045	23,744	-	28,573
Discounted future net cash flows	2,036	-	1,725	143	21,099	-	25,003
Total consolidated and equity interests in standardized measure of discounted future net cash flows	25,733	7,755	3,080	8,606	35,349	9,681	90,204

(1) Includes discounted future net cash flows attributable to Imperial Oil Limited of $2,322 million in 2016 and $3,344 million in 2017, in which there is a 30.4 percent noncontrolling interest.

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

Consolidated and Equity Interests — **2015**

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

Consolidated and Equity Interests — **2016**

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

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

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

Consolidated and Equity Interests (continued)	**2017**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2016	35,150	18,201	53,351
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases less related costs	10,375	255	10,630
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(24,911)	(7,358)	(32,269)
Development costs incurred during the year	7,066	2,020	9,086
Net change in prices, lifting and development costs	51,703	12,782	64,485
Revisions of previous reserves estimates	6,580	1,193	7,773
Accretion of discount	4,951	2,124	7,075
Net change in income taxes	(25,713)	(4,214)	(29,927)
Total change in the standardized measure during the year	30,051	6,802	36,853
Discounted future net cash flows as of December 31, 2017	65,201	25,003	90,204

OPERATING INFORMATION (unaudited)

	2017	2016	2015	2014	2013
Production of crude oil, natural gas liquids, bitumen and synthetic oil					
Net production	*(thousands of barrels daily)*				
United States	514	494	476	454	431
Canada/Other Americas	412	430	402	301	280
Europe	182	204	204	184	190
Africa	423	474	529	489	469
Asia	698	707	684	624	784
Australia/Oceania	54	56	50	59	48
Worldwide	2,283	2,365	2,345	2,111	2,202
Natural gas production available for sale					
Net production	*(millions of cubic feet daily)*				
United States	2,936	3,078	3,147	3,404	3,545
Canada/Other Americas	218	239	261	310	354
Europe	1,948	2,173	2,286	2,816	3,251
Africa	5	7	5	4	6
Asia	3,794	3,743	4,139	4,099	4,329
Australia/Oceania	1,310	887	677	512	351
Worldwide	10,211	10,127	10,515	11,145	11,836
	(thousands of oil-equivalent barrels daily)				
Oil-equivalent production *(1)*	3,985	4,053	4,097	3,969	4,175
Refinery throughput	*(thousands of barrels daily)*				
United States	1,508	1,591	1,709	1,809	1,819
Canada	383	363	386	394	426
Europe	1,510	1,417	1,496	1,454	1,400
Asia Pacific	690	708	647	628	779
Other Non-U.S.	200	190	194	191	161
Worldwide	4,291	4,269	4,432	4,476	4,585
Petroleum product sales *(2)*					
United States	2,190	2,250	2,521	2,655	2,609
Canada	499	491	488	496	464
Europe	1,597	1,519	1,542	1,555	1,497
Asia Pacific and other Eastern Hemisphere	1,164	1,140	1,124	1,085	1,206
Latin America	80	82	79	84	111
Worldwide	5,530	5,482	5,754	5,875	5,887
Gasoline, naphthas	2,262	2,270	2,363	2,452	2,418
Heating oils, kerosene, diesel oils	1,850	1,772	1,924	1,912	1,838
Aviation fuels	382	399	413	423	462
Heavy fuels	371	370	377	390	431
Specialty petroleum products	665	671	677	698	738
Worldwide	5,530	5,482	5,754	5,875	5,887
Chemical prime product sales *(2)*	*(thousands of metric tons)*				
United States	9,307	9,576	9,664	9,528	9,679
Non-U.S.	16,113	15,349	15,049	14,707	14,384
Worldwide	25,420	24,925	24,713	24,235	24,063

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

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

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

INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the Registrant's Annual Report on Form 10-K for 2015).
3(ii)	By-Laws, as revised effective November 1, 2017 (incorporated by reference to Exhibit 3(ii) to the Registrant's Report on Form 8-K of October 31, 2017).
10(iii)(a.1)	2003 Incentive Program, as approved by shareholders May 28, 2003.*
10(iii)(a.2)	Extended Provisions for Restricted Stock Agreements (incorporated by reference to Exhibit 10(iii)(a.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements – Settlement in Shares.*
10(iii)(b.1)	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 10(iii)(b.1) to the Registrant's Annual Report on Form 10-K for 2013).*
10(iii)(b.2)	Earnings Bonus Unit instrument.*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant's Annual Report on Form 10-K for 2014).*
10(iii)(c.3)	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant's Annual Report on Form 10-K for 2013).*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f.1) to the Registrant's Annual Report on Form 10-K for 2013).*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by reference to Exhibit 10(iii)(f.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors (incorporated by reference to Exhibit 10(iii)(f.3) to the Registrant's Annual Report on Form 10-K for 2014).*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated October 26, 2011 (incorporated by reference to Exhibit 10(iii)(f.4) to the Registrant's Annual Report on Form 10-K for 2015).*
12	Computation of ratio of earnings to fixed charges.
14	Code of Ethics and Business Conduct.

18	Preferability Letter of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
21	Subsidiaries of the registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31.1	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.
31.2	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Financial Officer.
31.3	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Principal Accounting Officer.
32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Chief Executive Officer.
32.2	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Financial Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
101	Interactive data files.

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

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

SIGNATURES

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

EXXON MOBIL CORPORATION

By: /s/ DARREN W. WOODS

(Darren W. Woods,
Chairman of the Board)

Dated February 28, 2018

POWER OF ATTORNEY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated and on February 28, 2018.

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

/s/ URSULA M. BURNS	Director
(Ursula M. Burns)	

/s/ KENNETH C. FRAZIER (Kenneth C. Frazier)	Director
/s/ STEVEN A. KANDARIAN (Steven A. Kandarian)	Director
/s/ DOUGLAS R. OBERHELMAN (Douglas R. Oberhelman)	Director
/s/ SAMUEL J. PALMISANO (Samuel J. Palmisano)	Director
/s/ STEVEN S REINEMUND (Steven S Reinemund)	Director
/s/ WILLIAM C. WELDON (William C. Weldon)	Director
/s/ ANDREW P. SWIGER (Andrew P. Swiger)	Senior Vice President (Principal Financial Officer)
/s/ DAVID S. ROSENTHAL (David S. Rosenthal)	Vice President and Controller (Principal Accounting Officer)