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

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PART I

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, longlterm, 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

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Financial	Earnings After Income Taxes 2017	2016	Average Capital Employed 2017	2016	Return on Average Capital Employed 2017	2016	Capital and Exploration Expenditures 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.*

	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.

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,	2,333	2,269	2,280	2,251	2,283	2,538	2,330	2,211	2,384	2,365
synthetic oil and bitumen										
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.

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

BUSINESS ENVIRONMENT AND RISK ASSESSMENT

Long-Term Business Outlook

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.

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.

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.

Commitments	Note Reference Number	2018	2019-2020	2021-2022	2023 and Beyond	Total
		Payments Due by Period				
			(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.

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.

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.

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)

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.

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.

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 straightlline 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.

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

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.

Equity Company Financial Summary	2017 Total	2017 ExxonMobil Share	2016 Total	2016 ExxonMobil Share	2015 Total	2015 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

	December 31, 2017		December 31, 2016	
Property, Plant and Equipment	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.

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".

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.

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 forwardlooking, 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.

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 Benefits
	U.S.	Non-U.S.	
	(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 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, 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**

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							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, 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 (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)