2021

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2021

or

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

For the transition period from _______ to _______

Commission File Number 1-2256

Exxon Mobil Corporation

(Exact name of registrant as specified in its charter)

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

5959 Las Colinas Boulevard, Irving, Texas 75039-2298
(Address of principal executive offices) (Zip Code)

(972) 940-6000
(Registrant’s telephone number, including area code)

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes R No ☐

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

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

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

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

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

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

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

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

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

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PART I

ITEM 1. BUSINESS

Exxon Mobil Corporation was incorporated in the State of New Jersey in 1882. Divisions and affiliated companies of ExxonMobil operate or market products in the United States and most other countries of the world. Our principal business involves exploration for, and production of, crude oil and natural gas; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen and biofuels. Affiliates of ExxonMobil conduct extensive research programs in support of these businesses.

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

The energy and petrochemical industries are highly competitive, both within the industries and also with other industries in supplying the energy, fuel, and chemical needs of industrial and individual consumers. Certain industry participants, including ExxonMobil, are expanding investments in lower-emission energy and emission-reduction services and technologies. The Corporation competes with other firms in the sale or purchase of needed goods and services in many national and international markets and employs all methods of competition which are lawful and appropriate for such purposes.

Operating data and industry segment information for the Corporation are contained in the Financial Section of this report under the following: “Management's Discussion and Analysis of Financial Condition and Results of Operations: Business Results” and “Note 18: Disclosures about Segments and Related Information”. Information on oil and gas reserves is contained in the “Oil and Gas Reserves” part of the “Supplemental Information on Oil and Gas Exploration and Production Activities” portion of the Financial Section of this report.

ExxonMobil has a long-standing commitment to the development of proprietary technology. We have a wide array of research programs designed to meet the needs identified in each of our business segments. ExxonMobil held over 8 thousand active patents worldwide at the end of 2021. For technology licensed to third parties, revenues totaled approximately $66 million in 2021. Although technology is an important contributor to the overall operations and results of our Company, the profitability of each business segment is not dependent on any individual patent, trade secret, trademark, license, franchise, or concession.

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

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

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

The number of regular employees was 63 thousand, 72 thousand, and 75 thousand at years ended 2021, 2020, and 2019, respectively. Regular employees are defined as active executive, management, professional, technical, and wage employees who work full time or part time for the Corporation and are covered by the Corporation’s benefit plans and programs.

As discussed in item 1A. Risk Factors in this report, compliance with existing and potential future government regulations, including taxes, environmental regulations, and other government regulations and policies that directly or indirectly affect the production and sale of our products, may have material effects on the capital expenditures, earnings, and competitive position of ExxonMobil. With respect to the environment, throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water, and ground, including, but not limited to, compliance with environmental regulations. These include a significant investment in refining infrastructure and technology to manufacture clean fuels, as well as projects to monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions, and expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2021 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.6 billion, of which $3.4 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $5.3 billion in 2022, with capital expenditures expected to account for approximately 30 percent of the total. Costs for 2023 are anticipated to be higher as the Low Carbon Solutions business matures and the Corporation progresses its emission-reduction plans.

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

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

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

ITEM 1A. RISK FACTORS

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

Supply and Demand

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

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

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

Other demand-related factors. Other factors that may affect the demand for oil, gas, and petrochemicals, and therefore impact our results, include technological improvements in energy efficiency; seasonal weather patterns; increased competitiveness of, or government policy support for, alternative energy sources; changes in technology that alter fuel choices, such as technological advances in energy storage that make wind and solar more competitive for power generation; changes in consumer preferences for our products, including consumer demand for alternative fueled or electric transportation or alternatives to plastic products; and broad-based changes in personal income levels. See also "Climate Change and the Energy Transition" below.

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

Other market factors. ExxonMobil's business results are also exposed to potential negative impacts due to changes in interest rates, inflation, currency exchange rates, and other local or regional market conditions. Market factors may also result in losses from commodity derivatives and other instruments we use to hedge price exposures or for trading purposes.

Government and Political Factors

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

Access limitations. A number of countries limit access to their oil and gas resources, including by restricting leasing or permitting activities, or may place resources off-limits from development altogether. Restrictions on production of oil and gas could increase to the extent governments view such measures as a viable approach for pursuing national and global energy and climate policies. Restrictions on foreign investment in the oil and gas sector tend to increase in times of high commodity prices, when national governments may have less need of outside sources of private capital. Many countries also restrict the import or export of certain products based on point of origin.

Restrictions on doing business. ExxonMobil is subject to laws and sanctions imposed by the United States or by other jurisdictions where we do business that may prohibit ExxonMobil or certain of its affiliates from doing business in certain countries, or restricting the kind of business that may be conducted. Such restrictions may provide a competitive advantage to competitors who may not be subject to comparable restrictions.

Lack of legal certainty. Some countries in which we do business lack well-developed legal systems, or have not yet adopted, or may be unable to maintain, clear regulatory frameworks for oil and gas development. Lack of legal certainty exposes our operations to increased risk of adverse or unpredictable actions by government officials, and also makes it more difficult for us to enforce our contracts. In some cases these risks can be partially offset by agreements to arbitrate disputes in an international forum, but the adequacy of this remedy may still depend on the local legal system to enforce an award.

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

- increases in taxes, duties, or government royalty rates (including retroactive claims);
- price controls;
- changes in environmental regulations or other laws that increase our cost of compliance or reduce or delay available business opportunities (including changes in laws affecting offshore drilling operations, water use, methane emissions, hydraulic fracturing, or use of new or recycled plastics);
- actions by policy-makers, regulators, or other actors to delay or deny necessary licenses and permits, restrict the availability of oil and gas leases or the transportation of our products, or otherwise require changes in the company's business or strategy that could result in reduced returns;
- adoption of regulations mandating efficiency standards, the use of alternative fuels or uncompetitive fuel components;
- adoption of government payment transparency regulations that could require us to disclose competitively sensitive commercial information, or that could cause us to violate the non-disclosure laws of other countries; and
- government actions to cancel contracts, re-denominate the official currency, renounce or default on obligations, renegotiate terms unilaterally, or expropriate assets.

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

We also may be adversely affected by the outcome of litigation, especially in countries such as the United States in which very large and unpredictable punitive damage awards may occur; by government enforcement proceedings alleging non-compliance with applicable laws or regulations; or by state and local government actors as well as private plaintiffs acting in parallel that attempt to use the legal system to promote public policy agendas (including seeking to reduce the production and sale of hydrocarbon products though litigation targeting the company or other industry participants), gain political notoriety, or obtain monetary awards from the company.

Security concerns. Successful operation of particular facilities or projects may be disrupted by civil unrest, acts of sabotage or terrorism, cybersecurity attacks, the application of national security laws or policies that result in restricting our ability to do business in a particular jurisdiction, and other local security concerns. Such concerns may require us to incur greater costs for security or to shut down operations for a period of time.

Climate Change and the Energy Transition

Net-zero scenarios. Driven by concern over the risks of climate change, a number of countries have adopted, or are considering the adoption of, regulatory frameworks to reduce greenhouse gas emissions including emissions from the production and use of oil and gas and their products. These actions are being taken both independently by national and regional governments and within the framework of United Nations Conference of the Parties summits under which many countries of the world have endorsed objectives to reduce the atmospheric concentration of CO2 over the coming decades, with an ambition ultimately to achieve "net-zero." Net-zero means that emissions of greenhouse gases from human activities would be balanced by actions that remove such gases from the atmosphere. Expectations for transition of the world's energy system to lower emission sources and ultimately net-zero derive from hypothetical scenarios that reflect many assumptions about the future and reflect substantial uncertainties. The company's objective to lead in the energy transition, including the company's announced ambition ultimately to achieve net-zero with respect to emissions from operations where ExxonMobil is the operator, carries risks that the transition, including underlying technologies, policies, and markets as discussed in more detail below, will not develop at the pace or in the manner expected by current net-zero scenarios. The success of our strategy for the energy transition will also depend on our ability to recognize key signposts of change in the global energy system on a timely basis, and our corresponding ability to direct investment to the technologies and businesses, at the appropriate stage of development, to best capitalize on our competitive strengths.

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

Technology and low carbon solutions. Achieving societal ambitions to reduce greenhouse gas emissions and ultimately achieve net-zero will require new technologies to reduce the cost and increase the scalability of alternative energy sources, as well as technologies such as carbon capture and storage (CCS). CCS technologies, focused initially on capturing and sequestering CO2 emissions from high-intensity industrial activities, can assist in meeting society's objective to mitigate atmospheric greenhouse gas levels while also helping ensure the availability of the reliable and affordable energy the world requires. ExxonMobil has established a Low Carbon Solutions (LCS) business unit to advance the development and deployment of these technologies and projects, including CCS, hydrogen and advanced biofuels, breakthrough energy efficiency processes, advanced energy-saving materials, and other technologies. The company's efforts include both in-house research and development and collaborative efforts with leading universities as well as commercial partners involved in advanced lower-emission energy technologies. Our future results and ability to grow our LCS business and succeed through the energy transition will depend in part on the success of these research and collaboration efforts and on our ability to adapt and apply the strengths of our current business model to providing the energy products of the future in a cost-competitive manner.

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

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

Operational and Other Factors

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

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

Project and portfolio management. The long-term success of ExxonMobil’s Upstream, Downstream, and Chemical businesses, as well as the future success of LCS and other emerging lower-emission investments, depends on complex, long-term, capital intensive projects. These projects in turn require a high degree of project management expertise to maximize efficiency. Specific factors that can affect the performance of major projects include our ability to: negotiate successfully with joint venturers, partners, governments, suppliers, customers, or others; model and optimize reservoir performance; develop markets for project outputs, whether through long-term contracts or the development of effective spot markets; manage changes in operating conditions and costs, including costs of third party equipment or services such as drilling rigs and shipping; prevent, to the extent possible, and respond effectively to unforeseen technical difficulties that could delay project start-up or cause unscheduled project downtime; and influence the performance of project operators where ExxonMobil does not perform that role. In addition to the effective management of individual projects, ExxonMobil’s success, including our ability to mitigate risk and provide attractive returns to shareholders, depends on our ability to successfully manage our overall portfolio, including diversification among types and locations of our projects, products produced, and strategies to divest assets. We may not be able to divest assets at a price or on the timeline we contemplate in our strategies. Additionally, we may retain certain liabilities following a divestment and could be held liable for past use or for different liabilities than anticipated.

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

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

Research and development and technological change. To maintain our competitive position, especially in light of the technological nature of our businesses and the need for continuous efficiency improvement, ExxonMobil’s technology, research, and development organizations must be successful and able to adapt to a changing market and policy environment, including developing technologies to help reduce greenhouse gas emissions. To remain competitive we must also continuously adapt and capture the benefits of new and emerging technologies, including successfully applying advances in the ability to process very large amounts of data to our businesses.

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

Cybersecurity. ExxonMobil is regularly subject to attempted cybersecurity disruptions from a variety of sources including state-sponsored actors. ExxonMobil's defensive preparedness includes multi-layered technological capabilities for prevention and detection of cybersecurity disruptions; non-technological measures such as threat information sharing with governmental and industry groups; internal training and awareness campaigns including routine testing of employee awareness and an emphasis on resiliency including business response and recovery. If the measures we are taking to protect against cybersecurity disruptions prove to be insufficient or if our proprietary data is otherwise not protected, ExxonMobil as well as our customers, employees, or third parties could be adversely affected. We are also exposed to potential harm from cybersecurity events that may affect the operations of third-parties, including our partners, suppliers, service providers (including providers of cloud-hosting services for our data or applications), and customers. Cybersecurity disruptions could cause physical harm to people or the environment; damage or destroy assets; compromise business systems; result in proprietary information being altered, lost, or stolen; result in employee, customer, or third-party information being compromised; or otherwise disrupt our business operations. We could incur significant costs to remedy the effects of a major cybersecurity disruption in addition to costs in connection with resulting regulatory actions, litigation, or reputational harm.

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

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information with regard to oil and gas producing activities follows:

1. Disclosure of Reserves

A. Summary of Oil and Gas Reserves at Year-End 2021

The table below summarizes the oil-equivalent proved reserves in each geographic area and by product type for consolidated subsidiaries and equity companies. Natural gas is converted to an oil-equivalent basis at six billion cubic feet per one million barrels. The Corporation has reported proved reserves on the basis of the average of the first-day-of-the-month price for each month during the last 12-month period. As a result of higher average prices in 2021, certain quantities of crude oil, bitumen, and natural gas that did not qualify as proved reserves in the prior year qualified as proved reserves at year-end 2021. Otherwise, no major discovery or other favorable or adverse event has occurred since December 31, 2021 that would cause a significant change in the estimated proved reserves as of that date.

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

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

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

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

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments and detailed analysis of well and reservoir information such as flow rates and reservoir pressures. Furthermore, the Corporation only records proved reserves for projects which have received significant funding commitments by management toward the development of the reserves. Although the Corporation is reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals, government policies, consumer preferences, and significant changes in crude oil and natural gas price levels. In addition, proved reserves could be affected by an extended period of low prices which could reduce the level of the Corporation’s capital spending and also impact our partners’ capacity to fund their share of joint projects.

B. Technologies Used in Establishing Proved Reserves Additions in 2021

Additions to ExxonMobil’s proved reserves in 2021 were based on estimates generated through the integration of available and appropriate geological, engineering and production data, utilizing well-established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements including high-quality 3-D and 4-D seismic data, calibrated with available well control information. The tools used to interpret the data included seismic processing software, reservoir modeling and simulation software, and data analysis packages.

In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increase the quality of and confidence in the reserves estimates.

C. Qualifications of Reserves Technical Oversight Group and Internal Controls over Proved Reserves

ExxonMobil has a dedicated Global Reserves and Resources group that provides technical oversight and is separate from the operating organization. Primary responsibilities of this group include oversight of the reserves estimation process for compliance with Securities and Exchange Commission (SEC) rules and regulations, review of annual changes in reserves estimates, and the reporting of ExxonMobil's proved reserves. This group also maintains the official company reserves estimates for ExxonMobil's proved reserves of crude oil, natural gas liquids, bitumen, synthetic oil, and natural gas. In addition, the group provides training to personnel involved in the reserves estimation and reporting process within ExxonMobil and its affiliates. The Manager of the Global Reserves and Resources group has more than 30 years of experience in reservoir engineering and reserves assessment, has a degree in Engineering and served on the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE). The group is staffed with individuals that have an average of more than 15 years of technical experience in the petroleum industry, including expertise in the classification and categorization of reserves under SEC guidelines. This group includes individuals who hold degrees in either Engineering or Geology.

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

2. Proved Undeveloped Reserves

At year-end 2021, approximately 6.3 billion oil-equivalent barrels (GOEB) of ExxonMobil's proved reserves were classified as proved undeveloped. This represents 34 percent of the 18.5 GOEB reported in proved reserves. This compares to 5.0 GOEB of proved undeveloped reserves reported at the end of 2020. During the year, ExxonMobil conducted development activities that resulted in the transfer of approximately 0.5 GOEB from proved undeveloped to proved developed reserves by year end. The largest transfers were related to development activities in the United States. During 2021, extensions and discoveries, primarily in the United States, Brazil, and Guyana, resulted in an addition of approximately 1.3 GOEB of proved undeveloped reserves, along with an increase of approximately 0.6 GOEB due to revisions primarily in Asia and Canada.

Overall, investments of $8.0 billion were made by the Corporation during 2021 to progress the development of reported proved undeveloped reserves, including $7.8 billion for oil and gas producing activities, along with additional investments for other non-oil and gas producing activities such as the construction of support infrastructure and other related facilities. These investments represented 65 percent of the $12.3 billion in total reported Upstream capital and exploration expenditures.

One of ExxonMobil's requirements for reporting proved reserves is that management has made significant funding commitments toward the development of the reserves. ExxonMobil has a disciplined investment strategy and many major fields require long lead-time in order to be developed. Development projects typically take several years from the time of recording proved undeveloped reserves to the start of production and can exceed five years for large and complex projects. Proved undeveloped reserves in Australia, Canada, Kazakhstan, the United States, and the United Arab Emirates have remained undeveloped for five years or more primarily due to constraints on the capacity of infrastructure, as well as the time required to complete development for very large projects. The Corporation is reasonably certain that these proved reserves will be produced; however, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals, government policies, consumer preferences, the pace of co-venturer/government funding, changes in the amount and timing of capital investments, and significant changes in crude oil and natural gas price levels. Of the proved undeveloped reserves that have been reported for five or more years, over 80 percent are contained in the aforementioned countries. In Australia, proved undeveloped reserves are associated with future compression for the Gorgon Jansz LNG project. In Canada, proved undeveloped reserves are related to Cold Lake operations. In Kazakhstan, the proved undeveloped reserves are related to the remainder of the Tengizchevroil joint venture development that includes a production license in the Tengiz - Korolev field complex. The Tengizchevroil joint venture is producing, and proved undeveloped reserves will continue to move to proved developed as approved development phases progress. In the United Arab Emirates, proved undeveloped reserves are associated with an approved development plan and continued drilling investment for the producing Upper Zakum field.

3. Oil and Gas Production, Production Prices and Production Costs

A. Oil and Gas Production

The table below summarizes production by final product sold and by geographic area for the last three years.

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

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

B. Production Prices and Production Costs

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

	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
During 2021				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	65.03	68.56	66.20	70.21	67.28	69.00	67.14
NGL, per barrel	32.24	30.51	42.31	54.57	32.62	43.07	33.65
Natural gas, per thousand cubic feet	3.02	2.92	11.83	1.67	2.11	6.64	4.33
Bitumen, per barrel	—	44.26	—	—	—	—	44.26
Synthetic oil, per barrel	—	64.73	—	—	—	—	64.73
Average production costs, per oil-equivalent barrel - total	8.33	22.47	25.31	18.92	7.16	5.14	12.15
Average production costs, per barrel - bitumen	—	22.69	—	—	—	—	22.69
Average production costs, per barrel - synthetic oil	—	48.87	—	—	—	—	48.87
Equity Companies							
Average production prices							
Crude oil, per barrel	67.06	—	62.60	—	65.85	—	66.01
NGL, per barrel	29.94	—	—	—	52.14	—	51.64
Natural gas, per thousand cubic feet	3.11	—	8.19	—	6.54	—	6.74
Average production costs, per oil-equivalent barrel - total	30.51	—	38.82	—	1.59	—	6.67
Total							
Average production prices							
Crude oil, per barrel	65.20	68.56	65.54	70.21	66.80	69.00	66.96
NGL, per barrel	32.23	30.51	42.31	54.57	47.10	43.07	37.27
Natural gas, per thousand cubic feet	3.02	2.92	9.89	1.67	5.50	6.64	5.21
Bitumen, per barrel	—	44.26	—	—	—	—	44.26
Synthetic oil, per barrel	—	64.73	—	—	—	—	64.73
Average production costs, per oil-equivalent barrel - total	9.24	22.47	31.79	19.04	4.06	5.14	10.92
Average production costs, per barrel - bitumen	—	22.69	—	—	—	—	22.69
Average production costs, per barrel - synthetic oil	—	48.87	—	—	—	—	48.87
During 2020							
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	34.97	37.26	41.39	42.27	39.39	36.67	38.31
NGL, per barrel	13.83	10.34	20.11	21.32	21.37	27.92	16.05
Natural gas, per thousand cubic feet	0.98	1.56	3.13	1.24	1.49	4.34	2.01
Bitumen, per barrel	—	17.71	—	—	—	—	17.71
Synthetic oil, per barrel	—	37.32	—	—	—	—	37.32
Average production costs, per oil-equivalent barrel - total	9.82	18.40	21.22	16.67	6.50	5.35	11.57
Average production costs, per barrel - bitumen	—	19.22	—	—	—	—	19.22
Average production costs, per barrel - synthetic oil	—	33.61	—	—	—	—	33.61
Equity Companies							
Average production prices							
Crude oil, per barrel	39.10	—	38.95	—	35.18	—	35.97
NGL, per barrel	11.05	—	—	—	30.02	—	29.58
Natural gas, per thousand cubic feet	1.19	—	3.85	—	3.14	—	3.20
Average production costs, per oil-equivalent barrel - total	25.13	—	30.74	—	1.63	—	5.34
Total							
Average production prices							
Crude oil, per barrel	35.35	37.26	41.11	42.27	38.07	36.67	37.95
NGL, per barrel	13.80	10.34	20.11	21.32	27.65	27.92	19.16
Natural gas, per thousand cubic feet	0.98	1.56	3.44	1.24	2.72	4.34	2.43
Bitumen, per barrel	—	17.71	—	—	—	—	17.71
Synthetic oil, per barrel	—	37.32	—	—	—	—	37.32
Average production costs, per oil-equivalent barrel - total	10.55	18.40	24.76	16.73	3.91	5.35	10.21
Average production costs, per barrel - bitumen	—	19.22	—	—	—	—	19.22
Average production costs, per barrel - synthetic oil	—	33.61	—	—	—	—	33.61

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

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

4. Drilling and Other Exploratory and Development Activities

A. Number of Net Productive and Dry Wells Drilled

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

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

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

Syncrude Operations. Syncrude is a joint venture established to recover shallow deposits of oil sands using open-pit mining methods to extract the crude bitumen, and then upgrade it to produce a high-quality, light (32 degrees API), sweet, synthetic crude oil. Imperial Oil Limited is the owner of a 25 percent interest in the joint venture. Exxon Mobil Corporation has a 69.6 percent interest in Imperial Oil Limited. In 2021, the company's share of net production of synthetic crude oil was about 62 thousand barrels per day and share of net acreage was about 55 thousand acres in the Athabasca oil sands deposit.

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

Kearl is located approximately 40 miles north of Fort McMurray, Alberta, Canada. Bitumen is extracted from oil sands and processed through bitumen extraction and froth treatment trains. The product, a blend of bitumen and diluent, is shipped to our refineries and to other third parties. Diluent is natural gas condensate or other light hydrocarbons added to the crude bitumen to facilitate transportation by pipeline and rail. During 2021, average net production at Kearl was about 251 thousand barrels per day.

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

5. Present Activities

A. Wells Drilling

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

B. Review of Principal Ongoing Activities

UNITED STATES

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

During the year, a total of 449.4 net exploration and development wells were completed in the inland lower 48 states. Development activities focused on liquids-rich opportunities in the onshore U.S., primarily in the Permian Basin of West Texas and New Mexico.

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

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

CANADA / OTHER AMERICAS

Canada

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

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

Argentina

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

Brazil

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

Guyana

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

EUROPE

Germany

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

Netherlands

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

United Kingdom

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

AFRICA

Angola

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

Chad

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

Equatorial Guinea

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

Mozambique

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

Nigeria

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

ASIA

Azerbaijan

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

Indonesia

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

Iraq

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

Kazakhstan

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

Malaysia

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

Qatar

Through our joint ventures with Qatar Energy, ExxonMobil’s net acreage totaled 65 thousand acres offshore at year-end 2021. ExxonMobil participated in 62.2 million tonnes per year gross liquefied natural gas capacity and 3.4 billion cubic feet per day of flowing gas capacity at year-end. During the year, a total of 4.8 net development wells were completed. The North Field Production Sustainment Integrated Drilling and Looping project was funded in 2021. Effective January 1, 2022, ExxonMobil no longer participates in the Qatar Liquefied Gas Company Limited (QG1) venture, representing 3.6 thousand net acres and 9.9 million tonnes per year gross liquefied natural gas capacity.

Russia

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

Thailand

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

United Arab Emirates

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

AUSTRALIA / OCEANIA

Australia

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

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

Papua New Guinea

ExxonMobil's net acreage totaled 3.4 million acres, of which 1.2 million net acres were offshore at year-end 2021. In 2021, ExxonMobil relinquished 2.1 million net offshore acres. The Papua New Guinea (PNG) liquefied natural gas integrated development includes gas production and processing facilities in the southern PNG Highlands, onshore and offshore pipelines, and a 6.9 million tonnes per year liquefied natural gas facility near Port Moresby.

WORLDWIDE EXPLORATION

At year-end 2021, exploration activities were under way in several areas in which ExxonMobil has no established production operations and thus are not included above. A total of 18.3 million net acres were held at year-end 2021.

6. Delivery Commitments

ExxonMobil sells crude oil and natural gas from its producing operations under a variety of contractual obligations, some of which may specify the delivery of a fixed and determinable quantity for periods longer than one year. ExxonMobil also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be a combination of our own production and the spot market. Worldwide, we are contractually committed to deliver approximately 28 million barrels of oil and 2,500 billion cubic feet of natural gas for the period from 2022 through 2024. We expect to fulfill the majority of these delivery commitments with production from our proved developed reserves. Any remaining commitments will be fulfilled with production from our proved undeveloped reserves and purchases on the open market as necessary.

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

A. Gross and Net Productive Wells

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

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

B. Gross and Net Developed Acreage

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

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

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

C. Gross and Net Undeveloped Acreage

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

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

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

D. Summary of Acreage Terms

UNITED STATES

Oil and gas exploration and production rights are acquired from mineral interest owners through a lease. Mineral interest owners include the Federal and State governments, as well as private mineral interest owners. Leases typically have an exploration period ranging from one to ten years, and a production period that normally remains in effect until production ceases. Under certain circumstances, a lease may be held beyond its exploration term even if production has not commenced. In some instances regarding private property, a “fee interest” is acquired where the underlying mineral interests are owned outright.

CANADA / OTHER AMERICAS

Canada

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

Argentina

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

Brazil

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

Guyana

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

EUROPE

Germany

Exploration concessions are granted for an initial maximum period of five years, with an unlimited number of extensions up to three years each. Extensions are subject to specific minimum work commitments. Production licenses are normally granted for 20 to 25 years with multiple possible extensions subject to production on the license.

Netherlands

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

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

United Kingdom

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

AFRICA

Angola

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

Chad

Exploration permits are issued for a period of five years, and are renewable for one or two further five-year periods. The terms and conditions of the permits, including relinquishment obligations, are specified in a negotiated convention. The production term is 30 years and in 2017 was extended by 20 years to 2050.

Equatorial Guinea

Exploration, development and production activities are governed by production sharing contracts negotiated with the State Ministry of Mines and Hydrocarbons. The production period for crude oil is 30 years.

Mozambique

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

In 2018, an interest was acquired in offshore blocks, A5-B, Z5-C and Z5-D. Terms for the three blocks are governed by their respective EPCCs, with blocks Z5-C and Z5-D having an initial exploration phase that expires in 2022 and block A5-B's initial exploration phase expiring in 2023 after being granted a one-year extension. The EPCCs provide a development and production period that expires 30 years after the approval of a plan of development.

Nigeria

Exploration and production activities in the deepwater offshore areas are typically governed by production sharing contracts (PSCs) with the national oil company, the Nigerian National Petroleum Corporation (NNPC). NNPC typically holds the underlying Oil Prospecting License (OPL) and any resulting Oil Mining Lease (OML). The terms of the PSCs are generally 30 years, including a 10-year exploration period (an initial exploration phase that can be divided into multiple optional periods) covered by an OPL. Upon commercial discovery, an OPL may be converted to an OML. Partial relinquishment is required under the PSC at the end of the 10-year exploration period, and OMLs have a 20-year production period that may be extended, subject to the partial relinquishment provision of the Petroleum Industry Act (PIA) enacted on August 16, 2021.

Some exploration activities are carried out in deepwater by joint ventures with local companies holding interests in an OPL. OPLs in deepwater offshore areas are valid for 10 years, while in all other areas the licenses are for five years. Demonstrating a commercial discovery is the basis for conversion of an OPL to an OML.

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

OMLs granted under the 1969 Petroleum Act, which include all deepwater OMLs, have a maximum term of 20 years without distinction for onshore or offshore location and are renewable, upon 12-months written notice, for another period of 20 years. OMLs not held by NNPC are also subject to a mandatory 50-percent relinquishment after the first 10 years of their duration.

ASIA

Azerbaijan

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

Indonesia

Exploration and production activities in Indonesia are generally governed by cooperation contracts, usually in the form of a production sharing contract (PSC), negotiated with BPMIGAS, a government agency established in 2002 to manage upstream oil and gas activities. In 2012, Indonesia's Constitutional Court ruled certain articles of law relating to BPMIGAS to be unconstitutional, but stated that all existing PSCs signed with BPMIGAS should remain in force until their expiry, and the functions and duties previously performed by BPMIGAS are to be carried out by the relevant Ministry of the Government of Indonesia until the promulgation of a new oil and gas law. By presidential decree, SKKMIGAS became the interim successor to BPMIGAS. The current PSCs have an exploration period of six years, which can be extended once for a period of four years with a total contract period of 30 years including an exploitation period. PSC terms can be extended for a maximum of 20 years for each extension with the approval of the government.

Iraq

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

Kazakhstan

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

Offshore exploration and production activities are governed by a production sharing agreement negotiated with the Republic of Kazakhstan. The exploration period is six years followed by separate appraisal periods for each discovery. The production period for each discovery, which includes development, is 20 years from the date of declaration of commerciality with the possibility of two 10-year extensions.

Malaysia

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

Qatar

The State of Qatar grants gas production development project rights to develop and supply gas from the offshore North Field to permit the economic development and production of gas reserves sufficient to satisfy the gas and LNG sales obligations of these projects. The initial terms for these rights generally extend for 25 years. Extensions and terms are subject to State of Qatar approval.

Russia

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

Thailand

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

United Arab Emirates

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

AUSTRALIA / OCEANIA

Australia

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

Papua New Guinea

Exploration and production activities are governed by the Oil and Gas Act. Petroleum prospecting licenses are granted for an initial term of six years with a five-year extension possible (an additional extension of three years is possible in certain circumstances). Generally, a 50-percent relinquishment of the license area is required at the end of the initial six-year term, if extended. Petroleum development licenses are granted for an initial 25-year period. An extension for further consecutive period(s) of up to 20 years may be granted at the Minister's discretion. Petroleum retention licenses may be granted for gas resources that are not commercially viable at the time of application, but may become commercially viable within the maximum possible retention time of 15 years. Petroleum retention licenses are granted for five-year terms, and may be extended, at the Minister's discretion, twice for the maximum retention time of 15 years. Extensions of petroleum retention licenses may be for periods of less than one year, renewable annually, if the Minister considers at the time of extension that the resources could become commercially viable in less than five years, provided that the total period of all extensions granted does not exceed 10 years.

Information with regard to the Downstream segment follows:

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

Refining Capacity At Year-End 2021 *(1)*

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

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

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

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

Retail Sites At Year-End 2021

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

Information with regard to the Chemical segment follows:

ExxonMobil's Chemical segment manufactures and sells petrochemicals. The Chemical business supplies olefins, polyolefins, aromatics, and a wide variety of other petrochemicals.

Chemical Complex Capacity At Year-End 2021 *(1)*

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

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

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

ITEM 3. LEGAL PROCEEDINGS

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

Refer to the relevant portions of “Note 16: Litigation and Other Contingencies” of the Financial Section of this report for additional information on legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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

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

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

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

Mr. Neil A. Chapman was President of ExxonMobil Chemical Company and Vice President of Exxon Mobil Corporation January 1, 2015 – December 31, 2017. He became Senior Vice President of Exxon Mobil Corporation on January 1, 2018, a position he continues to hold as of this filing date.

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

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

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

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

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

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

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

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

Len M. Fox	*Vice President and Controller*	
Held current title since:	March 1, 2021	Age: 58

Mr. Len M. Fox was Vice President, Chemical Business Services and Treasurer, ExxonMobil Chemical Company June 1, 2015 – January 31, 2020. He was Assistant Treasurer of Exxon Mobil Corporation February 1, 2020 – December 31, 2020. Following a special assignment, he became Vice President and Controller of Exxon Mobil Corporation on March 1, 2021, positions he continues to hold as of this filing date.

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

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

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

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

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

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

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

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

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

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

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

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

Theodore J. Wojnar, Jr.	*Vice President – Corporate Strategic Planning*	
Held current title since:	August 1, 2017	Age: 62

Mr. Theodore J. Wojnar, Jr. was President of ExxonMobil Research and Engineering Company April 1, 2011 – July 31, 2017. He became Vice President – Corporate Strategic Planning of Exxon Mobil Corporation on August 1, 2017, a position he continues to hold as of this filing date.

Officers are generally elected by the Board of Directors at its meeting on the day of each annual election of directors, with each such officer serving until a successor has been elected and qualified. The above-named officers are required to file reports under Section 16 of the Securities Exchange Act of 1934.

PART II

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

The principal market where ExxonMobil common stock (XOM) is traded is the New York Stock Exchange, although the stock is traded on other exchanges in and outside the United States.

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

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

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

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs
October 2021	-		-	
November 2021	-		-	
December 2021	-		-	
Total	—		—	(See Note 1)

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

Note 1 - In January 2022, the Corporation initiated a share repurchase program of up to $10 billion over 12 to 24 months.

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

- Consolidated financial statements, together with the report thereon of PricewaterhouseCoopers LLP *(PCAOB ID 238)* dated February 23, 2022, beginning with the section entitled “Report of Independent Registered Public Accounting Firm” and continuing through “Note 19: Income and Other Taxes”;
- “Supplemental Information on Oil and Gas Exploration and Production Activities” (unaudited); and
- “Frequently Used Terms” (unaudited).

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

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management’s Evaluation of Disclosure Controls and Procedures

As indicated in the certifications in Exhibit 31 of this report, the Corporation’s Chief Executive Officer, Chief Financial Officer, and Principal Accounting Officer have evaluated the Corporation’s disclosure controls and procedures as of December 31, 2021. Based on that evaluation, these officers have concluded that the Corporation’s disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Corporation in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to them in a manner that allows for timely decisions regarding required disclosures and are effective in ensuring that such information is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms.

Management’s Report on Internal Control Over Financial Reporting

Management, including the Corporation’s Chief Executive Officer, Chief Financial Officer, and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation’s financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation’s internal control over financial reporting was effective as of December 31, 2021.

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

Changes in Internal Control Over Financial Reporting

There were no changes during the Corporation’s last fiscal quarter that materially affected, or are reasonably likely to materially affect, the Corporation’s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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

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

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

ITEM 11. EXECUTIVE COMPENSATION

Incorporated by reference to the sections entitled "Director Compensation", "Compensation Committee Report", "Compensation Discussion and Analysis", "Executive Compensation Tables", and "Pay Ratio" of the registrant's 2022 Proxy Statement.

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

The information required under Item 403 of Regulation S-K is incorporated by reference to the sections "Director and Executive Officer Stock Ownership" and "Certain Beneficial Owners" of the registrant's 2022 Proxy Statement.

Equity Compensation Plan Information

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

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

(2) Available shares can be granted in the form of restricted stock or other stock-based awards. Includes 65,754,069 shares available for award under the 2003 Incentive Program and 350,700 shares available for award under the 2004 Non-Employee Director Restricted Stock Plan.

(3) Under the 2004 Non-Employee Director Restricted Stock Plan approved by shareholders in May 2004, and the related standing resolution adopted by the Board, each non-employee director automatically receives 8,000 shares of restricted stock when first elected to the Board and, if the director remains in office, an additional 2,500 restricted shares each following year. While on the Board, each non-employee director receives the same cash dividends on restricted shares as a holder of regular common stock, but the director is not allowed to sell the shares. The restricted shares may be forfeited if the director leaves the Board early.

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

Incorporated by reference to the portion entitled “Related Person Transactions and Procedures” of the section entitled “Director and Executive Officer Stock Ownership”; and the portion entitled “Director Independence” of the section entitled “Corporate Governance” of the registrant’s 2022 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Incorporated by reference to the portion entitled “Audit Committee” of the section entitled “Corporate Governance” and the section entitled “Ratification of Independent Auditors” of the registrant’s 2022 Proxy Statement.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

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

ITEM 16. FORM 10-K SUMMARY

None.

FINANCIAL SECTION

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

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

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

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

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

(3) Prime product sales are total product sales including ExxonMobil's share of equity company volumes and finished-product transfers to the Downstream.

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

(1) Debt net of cash.

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

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

Cash Flow From Operations and Asset Sales

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

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

Capital Employed

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

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

Return on Average Capital Employed

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

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

Structural Cost Savings

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

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

Earnings (Loss) excluding Identified Items

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

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

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

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

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

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

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

FORWARD-LOOKING STATEMENTS

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

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

OVERVIEW

The following discussion and analysis of ExxonMobil's financial results, as well as the accompanying financial statements and related notes to consolidated financial statements to which they refer, are the responsibility of the management of Exxon Mobil Corporation. The Corporation's accounting and financial reporting fairly reflect its integrated business model involving exploration for, and production of, crude oil and natural gas, manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen, and biofuels. ExxonMobil's operating segments are Upstream, Downstream, and Chemical. Where applicable ExxonMobil voluntarily discloses additional U.S., Non-U.S. and regional splits to help investors better understand the company's operations.

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

ExxonMobil, with its resource base, financial strength, disciplined investment approach and technology portfolio, is well-positioned to participate in substantial investments to develop new energy supplies. The company's integrated business model, with significant investments in Upstream, Downstream and Chemical segments and Low Carbon Solutions business, generally reduces the Corporation's risk from changes in commodity prices. While commodity prices depend on supply and demand and may be volatile on a short-term basis, ExxonMobil's investment decisions are grounded on fundamentals reflected in our long-term business outlook, and use a disciplined approach in selecting and pursuing the most attractive investment opportunities. The corporate plan is a fundamental annual management process that is the basis for setting operating and capital objectives in addition to providing the economic assumptions used for investment evaluation purposes. The foundation for the assumptions supporting the corporate plan is the Energy Outlook and corporate plan volume projections are based on individual field production profiles, which are also updated at least annually. Price ranges for crude oil, natural gas, including price differentials, refinery and chemical margins, volumes, development and operating costs, including greenhouse gas emission prices, and foreign currency exchange rates are based on corporate plan assumptions developed annually by major region and are utilized for investment evaluation purposes. Major investment opportunities are evaluated over a range of potential market conditions. Once major investments are made, a reappraisal process is completed to ensure relevant lessons are learned and improvements are incorporated into future projects.

BUSINESS ENVIRONMENT

Long-Term Business Outlook

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

By 2050, the world's population is projected at around 9.7 billion people, or about 2 billion more than in 2019. Coincident with this population increase, the Corporation expects worldwide economic growth to average close to 2.5 percent per year, with economic output growing by around 125 percent by 2050 compared to 2019. As economies and populations grow, and as living standards improve for billions of people, the need for energy is expected to continue to rise. Even with significant efficiency gains, global energy demand is projected to rise by almost 15 percent from 2019 to 2050. This increase in energy demand is expected to be driven by developing countries (i.e., those that are not member nations of the Organisation for Economic Co-operation and Development (OECD)).

As expanding prosperity drives global energy demand higher, increasing use of energy-efficient technologies and practices as well as lower-emission products will continue to help significantly reduce energy consumption and emissions per unit of economic output over time. Substantial efficiency gains are likely in all key aspects of the world's economy through 2050, affecting energy requirements for power generation, transportation, industrial applications, and residential and commercial needs.

Under our Outlook, global electricity demand is expected to increase almost 75 percent from 2019 to 2050, with developing countries likely to account for about 80 percent of the increase. Consistent with this projection, power generation is expected to remain the largest and fastest growing major segment of global primary energy demand, supported by a wide variety of energy sources. The share of coal-fired generation is expected to decline substantially and approach 15 percent of the world's electricity in 2050, versus nearly 35 percent in 2019, in part as a result of policies to improve air quality as well as reduce greenhouse gas emissions to address risks related to climate change. From 2019 to 2050, the amount of electricity supplied using natural gas, nuclear power, and renewables is expected to more than double, accounting for the entire growth in electricity supplies and offsetting the reduction of coal. Electricity from wind and solar is expected to increase more than 600 percent, helping total renewables (including other sources, e.g. hydropower) to account for about 80 percent of the increase in electricity supplies worldwide through 2050. Total renewables are expected to reach about 50 percent of global electricity supplies by 2050. Natural gas and nuclear are also expected to increase shares over the period to 2050, reaching more than 25 percent and about 10 percent of global electricity supplies, respectively, by 2050. Supplies of electricity by energy type will reflect significant differences across regions reflecting a wide range of factors including the cost and availability of various energy supplies and policy developments.

Under our Outlook, energy for transportation - including cars, trucks, ships, trains and airplanes - is expected to increase by almost 25 percent from 2019 to 2050. Transportation energy demand is expected to account for over 40 percent of the growth in liquid fuels demand worldwide over this period. Light-duty vehicle demand for liquid fuels is projected to peak by around 2025 and then decline to levels seen in the early-2000s by 2050 as the impact of better fuel economy and significant growth in electric cars, led by China, Europe, and the United States, work to offset growth in the worldwide car fleet of about 75 percent. By 2050, light-duty vehicles are expected to account for around 15 percent of global liquid fuels demand. During the same time period, nearly all the world's commercial transportation fleets are expected to continue to run on liquid fuels, including biofuels, which are widely available and offer practical advantages in providing a large quantity of energy in small volumes.

Liquid fuels provide the largest share of global energy supplies today reflecting broad-based availability, affordability, ease of transportation, and fitness as a practical solution to meet a wide variety of needs. By 2050, global demand for liquid fuels is projected to grow to approximately 114 million barrels of oil equivalent per day, an increase of about 14 percent from 2019. The non-OECD share of global liquid fuels demand is expected to increase to nearly 70 percent by 2050, as liquid fuels demand in the OECD is expected to decline by more than 20 percent. Much of the global liquid fuels demand today is met by crude production from traditional conventional sources; these supplies will remain important, and significant development activity is expected to offset much of the natural declines from these fields. At the same time, a variety of emerging supply sources - including tight oil, deepwater, oil sands, natural gas liquids and biofuels - are expected to grow to help meet rising demand. The world's resource base is sufficient to meet projected demand through 2050 as technology advances continue to expand the availability of economic and lower-carbon supply options. However, timely investments will remain critical to meeting global needs with reliable and affordable supplies.

Natural gas is a lower-emission, versatile and practical fuel for a wide variety of applications, and it is expected to grow the most of any primary energy type from 2019 to 2050, meeting about 55 percent of global energy demand growth. Global natural gas demand is expected to rise nearly 35 percent from 2019 to 2050, with more than half of that increase coming from the Asia Pacific region. Significant growth in supplies of unconventional gas - the natural gas found in shale and other tight rock formations - will help meet these needs. In total, about 50 percent of the growth in natural gas supplies is expected to be from unconventional sources. At the same time, conventionally-produced natural gas is likely to remain the cornerstone of global supply, meeting more than two-thirds of worldwide demand in 2050. Liquefied natural gas (LNG) trade will expand significantly, meeting about 40 percent of the increase in global demand growth, with much of this supply expected to help meet rising demand in Asia Pacific.

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

To meet this projected demand under our Outlook, the Corporation anticipates that the world's available oil and gas resource base will grow not only from new discoveries, but also from increases in previously discovered fields. Technology will underpin these increases. The investments to develop and supply resources to meet global demand through 2050 will be significant. This reflects a fundamental aspect of the oil and natural gas business as the International Energy Agency (IEA) describes in its World Energy Outlook 2021.

International accords and underlying regional and national regulations covering greenhouse gas emissions continue to evolve with uncertain timing and outcome, making it difficult to predict their business impact. For many years, the Corporation has taken into account policies established to reduce energy-related greenhouse gas emissions in its long-term Energy Outlook. The climate accord reached at the Conference of the Parties (COP 21) in Paris set many new goals, and many related policies are still emerging. Our Energy Outlook reflects an environment with increasingly stringent climate policies and is consistent with the global aggregation of Nationally Determined Contributions (NDCs), as available at the end of 2020, which were submitted by signatories to the United Nations Framework Convention on Climate Change (UNFCCC) 2015 Paris Agreement. Our Energy Outlook seeks to identify potential impacts of climate-related policies, which often target specific sectors. It estimates potential impacts of these policies on consumer energy demand by using various assumptions and tools - including, depending on the sector, and, as applicable, use of a proxy cost of carbon or assessment of targeted policies (e.g. automotive fuel economy standards). For purposes of the Energy Outlook, a proxy cost on energy-related CO2 emissions is assumed to reach about $100 per metric ton in 2050 in OECD nations. China and other leading non-OECD nations are expected to trail OECD policy initiatives. Nevertheless, as people and nations look for ways to reduce risks of global climate change, they will continue to need practical solutions that do not jeopardize the affordability or reliability of the energy they need. The Corporation continues to monitor the updates to the NDCs that nations provided around COP 26 in Glasgow in November 2021 as well as other policy developments in light of net-zero ambitions recently formulated by some nations.

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

Leading the Drive to Net Zero

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

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

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

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

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

Recent Business Environment

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

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

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

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

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

BUSINESS RESULTS

Upstream

ExxonMobil continues to sustain a diverse growth portfolio of exploration and development opportunities, which enables the Corporation to be selective, maximizing shareholder value and mitigating political and technical risks. ExxonMobil’s fundamental strategies guide our global Upstream business, including capturing material and accretive opportunities to continually high-grade the resource portfolio, selectively developing attractive oil and natural gas resources, developing and applying high-impact technologies, and pursuing productivity and efficiency gains as well as a reduction in greenhouse gas emissions. These strategies are underpinned by a relentless focus on operational excellence, development of our employees, and investment in the communities within which we operate.

As future development projects and drilling activities bring new production online, the Corporation expects a shift in the geographic mix and in the type of opportunities from which volumes are produced. Based on current investment plans, the proportion of oil-equivalent production from the Americas is generally expected to increase over the next several years. About half of the Corporation's global production comes from unconventional, deepwater and LNG resources. This proportion is generally expected to grow over the next few years.

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

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

ExxonMobil believes prices over the long term will continue to be driven by market supply and demand, with the demand side largely being a function of general economic activities, alternative energy sources, levels of prosperity, technology advances, consumer preference and government policies. On the supply side, prices may be significantly impacted by political events, the actions of OPEC and other large government resource owners, and other factors. To manage the risks associated with price, ExxonMobil tests the resiliency of its annual plans and major investments across a range of price scenarios.

Key Recent Events

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

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

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

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

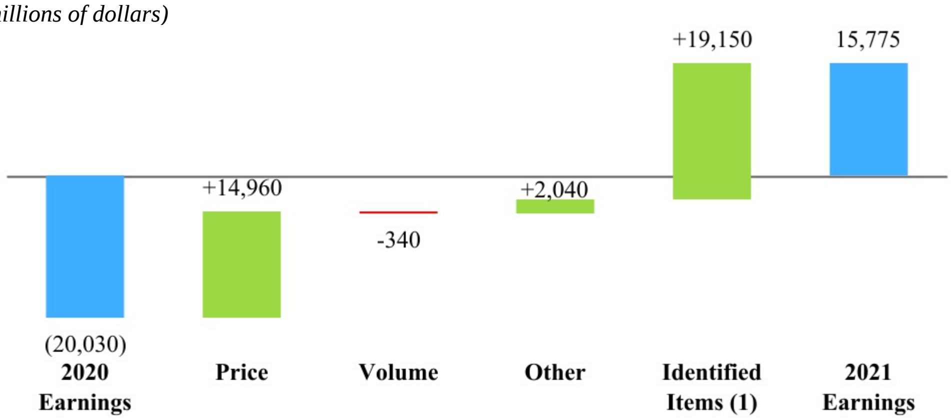
Mozambique: The Area 4 Coral South Floating LNG (FLNG) development continues as planned, targeting start-up in 2022, making Mozambique an LNG exporter. The Coral Sul FLNG vessel began tow to field in November 2021.

Upstream Financial Results

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

2021 Upstream Earnings Factor Analysis

(millions of dollars)



Price – Higher realizations increased earnings by $14,960 million.

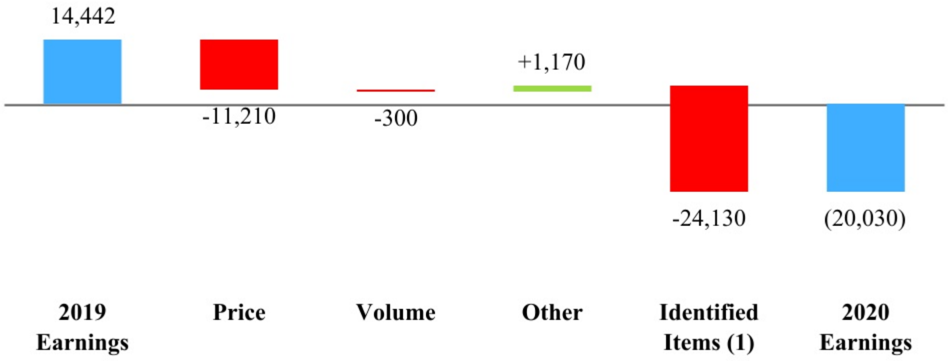
Volume – Unfavorable volume and mix effects decreased earnings by $340 million.

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

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

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

2020 Upstream Earnings Factor Analysis
(millions of dollars)



Price – Lower realizations reduced earnings by $11,210 million.

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

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

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

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

Upstream Operational Results

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

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

2021

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

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

2020

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

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

Upstream Additional Information

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

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

Listed below are descriptions of ExxonMobil's volumes reconciliation factors which are provided to facilitate understanding of the terms.

Entitlements - Net Interest are changes to ExxonMobil's share of production volumes caused by non-operational changes to volume-determining factors. These factors consist of net interest changes specified in Production Sharing Contracts (PSCs) which typically occur when cumulative investment returns or production volumes achieve defined thresholds, changes in equity upon achieving pay-out in partner investment carry situations, equity redeterminations as specified in venture agreements, or as a result of the termination or expiry of a concession. Once a net interest change has occurred, it typically will not be reversed by subsequent events, such as lower crude oil prices.

Entitlements - Price, Spend and Other are changes to ExxonMobil's share of production volumes resulting from temporary changes to non-operational volume-determining factors. These factors include changes in oil and gas prices or spending levels from one period to another. According to the terms of contractual arrangements or government royalty regimes, price or spending variability can increase or decrease royalty burdens and/or volumes attributable to ExxonMobil. For example, at higher prices, fewer barrels are required for ExxonMobil to recover its costs. These effects generally vary from period to period with field spending patterns or market prices for oil and natural gas. Such factors can also include other temporary changes in net interest as dictated by specific provisions in production agreements.

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

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

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

Downstream

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

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

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

Refining margins are largely driven by differences in commodity prices and are a function of the difference between what a refinery pays for its raw materials and the market prices for the range of products produced. Crude oil and many products are widely traded with published prices, including those quoted on multiple exchanges around the world (e.g. New York Mercantile Exchange and Intercontinental Exchange). Prices for these commodities are determined by the global marketplace and are influenced by many factors, including global and regional supply/demand balances, inventory levels, industry refinery operations, import/export balances, currency fluctuations, seasonal demand, weather, and political climate. ExxonMobil's outlook is that industry refining margins will remain volatile subject to shifting consumer demand as well as capacity changes from refinery additions and closures. ExxonMobil's significant integration both within the Downstream value chains including lubricants, logistics, trading, refining, and marketing, as well as with Upstream and Chemical, improves our ability to generate shareholder value in a variety of market conditions.

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

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

Key Recent Events

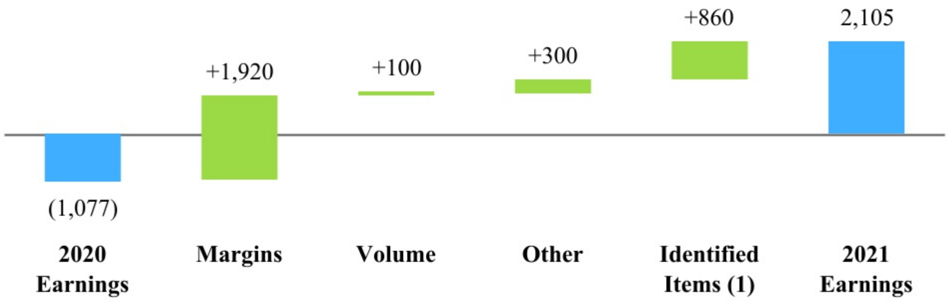
Lower-emission fuels: ExxonMobil announced plans for more than 40 thousand barrels per day of lower-emission fuels by 2025, including a new renewable diesel unit at the Strathcona refinery, and purchase agreements with Global Clean Energy in the U.S. and Biojet AS in Norway.

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

Downstream Financial Results

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

2021 Downstream Earnings Factor Analysis
(millions of dollars)



Margins – Increased earnings by $1,920 million as industry refining conditions improved.

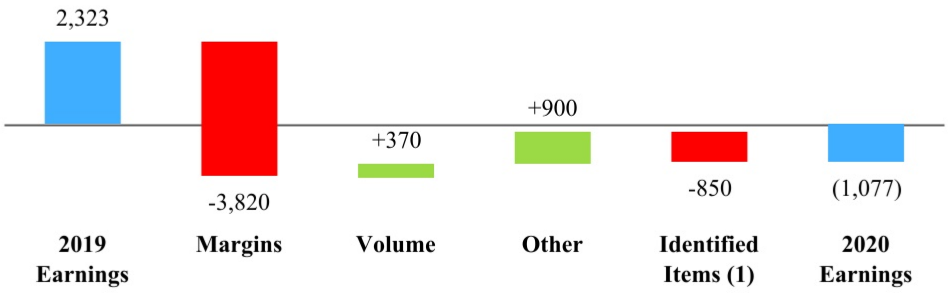
Volume – Increased earnings by $100 million reflecting demand recovery and favorable mix.

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

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

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

2020 Downstream Earnings Factor Analysis
(millions of dollars)



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

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

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

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

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

Downstream Operational Results

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

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

Chemical

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

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

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

Key Recent Events

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

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

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

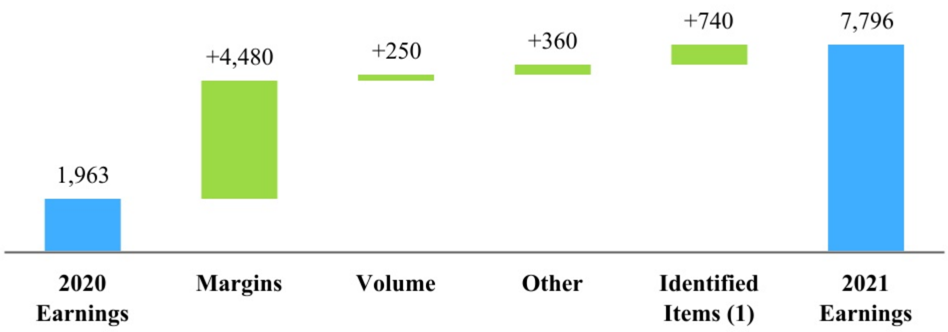
Santoprene divestment: ExxonMobil Chemical Company sold its global *Santoprene* business to Celanese. The sale included two manufacturing sites, one in the United States and one in the United Kingdom.

Chemical Financial Results

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

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

2021 Chemical Earnings Factor Analysis
(millions of dollars)



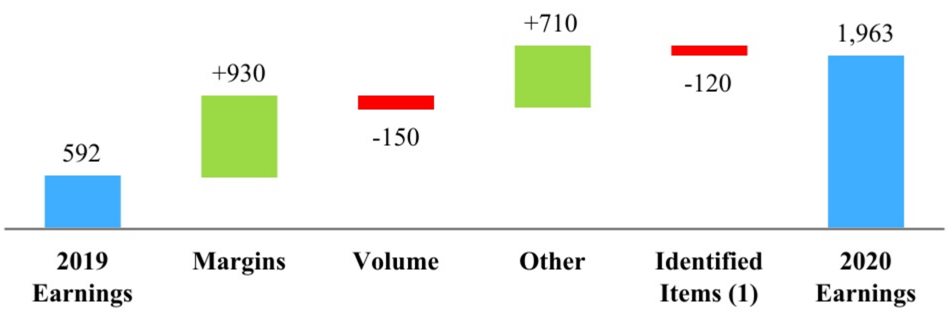
Margins – Stronger margins increased earnings by $4,480 million driven by resilient demand and industry supply constraints.

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

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

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

2020 Chemical Earnings Factor Analysis
(millions of dollars)



Margins – Stronger margins increased earnings by $930 million.

Volume – Lower volumes decreased earnings by $150 million.

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

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

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

Chemical Operational Results

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

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

Corporate and Financing

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

Corporate and Financing Financial Results

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

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

2021

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

2020

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

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

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

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

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

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

To support cash flows in future periods, the Corporation will need to continually find or acquire and develop new fields, and continue to develop and apply new technologies and recovery processes to existing fields, in order to maintain or increase production. After a period of production at plateau rates, it is the nature of oil and gas fields to eventually produce at declining rates for the remainder of their economic life. Decline rates can vary widely by individual field due to a number of factors, including, but not limited to, the type of reservoir, fluid properties, recovery mechanisms, work activity, and age of the field. In particular, the Corporation's key tight-oil plays have higher initial decline rates which tend to moderate over time. Furthermore, the Corporation's net interest in production for individual fields can vary with price and the impact of fiscal and commercial terms.

The Corporation has long been successful at mitigating the effects of natural field decline through disciplined investments in quality opportunities and project execution. The Corporation anticipates several projects will come online over the next few years providing additional production capacity. However, actual volumes will vary from year to year due to the timing of individual project start-ups; operational outages; reservoir performance; performance of enhanced oil recovery projects; regulatory changes; the impact of fiscal and commercial terms; asset sales; weather events; price effects on production sharing contracts; and changes in the amount and timing of investments that may vary depending on the oil and gas price environment. The Corporation's cash flows are also highly dependent on crude oil and natural gas prices. Please refer to Item 1A. Risk Factors for a more complete discussion of risks.

The Corporation's financial strength enables it to make large, long-term capital expenditures. Capital and exploration expenditures in 2021 were $16.6 billion, reflecting the Corporation's continued active investment program. The Corporation plans to invest in the range of $21 billion to $24 billion in 2022.

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

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

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

Cash Flow from Operating Activities

2021

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

2020

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

Cash Flow from Investing Activities

2021

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

2020

Cash used in investing activities netted to $18.5 billion in 2020, $4.6 billion lower than 2019. Spending for property, plant and equipment of $17.3 billion decreased $7.1 billion from 2019. Proceeds from asset sales and returns of investments of $1.0 billion compared to $3.7 billion in 2019. Additional investments and advances were $1.0 billion higher in 2020, while proceeds from other investing activities including collection of advances increased by $1.2 billion.

Cash Flow from Financing Activities

2021

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

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

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

2020

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

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

During 2020, Exxon Mobil Corporation acquired 8 million shares of its common stock for the treasury. Purchases were made to offset shares or units settled in shares issued in conjunction with the company's benefit plans and programs. Shares outstanding decreased from 4,234 million to 4,233 million at the end of 2020.

Contractual Obligations

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

In addition, the Corporation also enters into commodity purchase obligations (volumetric commitments but no fixed or minimum price) which are resold shortly after purchase, either in an active, highly liquid market or under long-term, unconditional sales contracts with similar pricing terms. Examples include long-term, noncancelable LNG and natural gas purchase commitments and commitments to purchase refinery products at market prices. These commitments are not meaningful in assessing liquidity and cash flow, because the purchases will be offset in the same periods by cash received from the related sales transactions.

Take-or-pay obligations are noncancelable, long-term commitments for goods and services. Unconditional purchase obligations are those long-term commitments that are noncancelable or cancelable only under certain conditions, and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. These obligations mainly pertain to pipeline, manufacturing supply and terminal agreements. The total obligation at year-end 2021 for take-or-pay and unconditional purchase obligations was $30,031 million. Cash payments expected in 2022 and 2023 are $4,004 million and $3,560 million, respectively.

Guarantees

The Corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2021 for guarantees relating to notes, loans and performance under contracts (Note 16). Where guarantees for environmental remediation and other similar matters do not include a stated cap, the amounts reflect management's estimate of the maximum potential exposure. These guarantees are not reasonably likely to have a material effect on the Corporation's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Financial Strength

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

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

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

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

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

Litigation and Other Contingencies

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

CAPITAL AND EXPLORATION EXPENDITURES

Capital and exploration expenditures (Capex) represents the combined total of additions at cost to property, plant and equipment, and exploration expenses on a before-tax basis from the Consolidated Statement of Income. ExxonMobil's Capex includes its share of similar costs for equity companies. Capex excludes assets acquired in nonmonetary exchanges, the value of ExxonMobil shares used to acquire assets, and depreciation on the cost of exploration support equipment and facilities recorded to property, plant and equipment when acquired. While ExxonMobil's management is responsible for all investments and elements of net income, particular focus is placed on managing the controllable aspects of this group of expenditures.

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

(1) Exploration expenses included.

Capex in 2021 was $16.6 billion, as the Corporation continued to pursue opportunities to find and produce new supplies of oil and natural gas to meet global demand for energy. The Corporation plans to invest in the range of $21 billion to $24 billion in 2022. Included in the 2022 capital spend range is $8.3 billion of firm capital commitments. An additional $10.7 billion of firm capital commitments have been made for years 2023 and beyond. Actual spending could vary depending on the progress of individual projects and property acquisitions.

Upstream spending of $12.3 billion in 2021 was down 15 percent from 2020, primarily in the U.S. Permian Basin. Investments in 2021 included the U.S. Permian Basin and key development projects in Guyana and Brazil. Development projects typically take several years from the time of recording proved undeveloped reserves to the start of production and can exceed five years for large and complex projects. The percentage of proved developed reserves was 66 percent of total proved reserves at year-end 2021, and has been over 60 percent for the last ten years.

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

TAXES

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

2021

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

2020

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

ENVIRONMENTAL MATTERS

Environmental Expenditures

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

Throughout ExxonMobil's businesses, new and ongoing measures are taken to prevent and minimize the impact of our operations on air, water and ground. These include a significant investment in refining infrastructure and technology to manufacture clean fuels, as well as projects to monitor and reduce nitrogen oxide, sulfur oxide and greenhouse gas emissions, and expenditures for asset retirement obligations. Using definitions and guidelines established by the American Petroleum Institute, ExxonMobil's 2021 worldwide environmental expenditures for all such preventative and remediation steps, including ExxonMobil's share of equity company expenditures, were $4.6 billion, of which $3.4 billion were included in expenses with the remainder in capital expenditures. The total cost for such activities is expected to increase to approximately $5.3 billion in 2022, with capital expenditures expected to account for approximately 30 percent of the total. Costs for 2023 are anticipated to be higher as the Low Carbon Solutions business matures and the Corporation progresses its emission-reduction plans.

Environmental Liabilities

The Corporation accrues environmental liabilities when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. ExxonMobil has accrued liabilities for probable environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency has identified ExxonMobil as one of the potentially responsible parties. The involvement of other financially responsible companies at these multiparty sites could mitigate ExxonMobil's actual joint and several liability exposure. At present, no individual site is expected to have losses material to ExxonMobil's operations or financial condition. Consolidated company provisions made in 2021 for environmental liabilities were $146 million ($263 million in 2020) and the balance sheet reflects liabilities of $807 million as of December 31, 2021, and $902 million as of December 31, 2020.

MARKET RISKS

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

(1) Consolidated subsidiaries.

Crude oil, natural gas, petroleum product and chemical prices have fluctuated in response to changing market forces. The impacts of these price fluctuations on earnings from Upstream, Downstream and Chemical operations have varied. For the year 2022, a $1 per barrel change in the weighted-average realized price of oil would have approximately a $500 million annual after-tax effect on Upstream consolidated plus equity company earnings, excluding the impact of derivatives. Similarly, a $0.10 per thousand cubic feet change in the worldwide average gas realization would have approximately a $155 million annual after-tax effect on Upstream consolidated plus equity company earnings, excluding the impact of derivatives. For any given period, the extent of actual benefit or detriment will be dependent on the price movements of individual types of crude oil, results of trading activities, taxes and other government take impacts, price adjustment lags in long-term gas contracts, and crude and gas production volumes. Accordingly, changes in benchmark prices for crude oil and natural gas only provide broad indicators of changes in the earnings experienced in any particular period.

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

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

In general, segment results are not dependent on the ability to sell and/or purchase products to/from other segments. Instead, where such sales take place, they are the result of efficiencies and competitive advantages of integrated refinery and chemical complexes. Additionally, intersegment sales are at market-based prices. The products bought and sold between segments can also be acquired in worldwide markets that have substantial liquidity, capacity, and transportation capabilities. Refer to Note 18 for additional information on intersegment revenue.

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

The Corporation has an active asset management program in which underperforming assets are either improved to acceptable levels or considered for divestment. The asset management program includes a disciplined, regular review to ensure that assets are contributing to the Corporation’s strategic objectives.

Risk Management

The Corporation’s size, strong capital structure, geographic diversity and the complementary nature of the Upstream, Downstream and Chemical businesses reduce the Corporation’s enterprise-wide risk from changes in commodity prices, currency rates and interest rates. In addition, the Corporation uses commodity-based contracts, including derivatives, to manage commodity price risk and to generate returns from trading. The Corporation’s commodity derivatives are not accounted for under hedge accounting. At times, the Corporation also enters into currency and interest rate derivatives, none of which are material to the Corporation’s financial position as of December 31, 2021 and 2020, or results of operations for the years ended 2021, 2020 and 2019. Credit risk associated with the Corporation’s derivative position is mitigated by several factors, including the use of derivative clearing exchanges and the quality of and financial limits placed on derivative counterparties. No material market or credit risks to the Corporation’s financial position, results of operations or liquidity exist as a result of the derivatives described in Note 13. The Corporation maintains a system of controls that includes the authorization, reporting and monitoring of derivative activity.

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

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

CRITICAL ACCOUNTING ESTIMATES

The Corporation's accounting and financial reporting fairly reflect its integrated business model involving exploration for, and production of, crude oil and natural gas; manufacture, trade, transport and sale of crude oil, natural gas, petroleum products, petrochemicals and a wide variety of specialty products; and pursuit of lower-emission business opportunities including carbon capture and storage, hydrogen and biofuels. The preparation of financial statements in conformity with U.S. Generally Accepted Accounting Principles (GAAP) requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The Corporation's accounting policies are summarized in Note 1.

Oil and Natural Gas Reserves

The estimation of proved oil and natural gas reserve volumes is an ongoing process based on rigorous technical evaluations, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressure declines, development and production costs, and other factors. The estimation of proved reserves is controlled by the Corporation through long-standing approval guidelines. Reserve changes are made within a well-established, disciplined process driven by senior level geoscience and engineering professionals, assisted by the Global Reserves and Resources Group which has significant technical experience, culminating in reviews with and approval by senior management. Notably, the Corporation does not use specific quantitative reserve targets to determine compensation. Key features of the reserve estimation process are covered in Disclosure of Reserves in Item 2.

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

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

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

  The Corporation is reasonably certain that proved reserves will be produced. However, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals, government policy, consumer preferences and significant changes in oil and natural gas price levels.

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

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

Unit-of-Production Depreciation

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

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

To the extent that proved reserves for a property are substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes.

Impairment

The Corporation tests assets or groups of assets for recoverability on an ongoing basis whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. The Corporation has a robust process to monitor for indicators of potential impairment across its asset groups throughout the year. This process is aligned with the requirements of ASC 360 and ASC 932, and relies, in part, on the Corporation’s planning and budgeting cycle.

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

In general, the Corporation does not view temporarily low prices or margins as an indication of impairment. Management believes that prices over the long term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments and technology, and efficiency advancements. OPEC investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities, alternative energy sources and levels of prosperity. During the lifespan of its major assets, the Corporation expects that oil and gas prices and industry margins will experience significant volatility, and consequently these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the Corporation considers recent periods of operating losses in the context of its longer-term view of prices and margins.

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

If events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the Corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in recoverability assessments are based on the assumptions developed in the Corporate Plan, which is reviewed and approved by the Board of Directors, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the Corporation’s assumptions of future capital allocations, crude oil and natural gas commodity prices including price differentials, refining and chemical margins, volumes, development and operating costs including greenhouse gas emission prices, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management’s estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. The greenhouse gas emission prices reflect existing or anticipated policy actions that countries or localities may take in support of Paris Accord pledges. While third-party scenarios, such as the International Energy Agency Net Zero Emissions by 2050, may be used to test the resiliency of the Corporation's businesses or strategies, they are not used as a basis for developing future cash flows for impairment assessments.

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

Other Impairment Estimates. Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the Corporation's future development plans, the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

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

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

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

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

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

Factors which could put further assets at risk of impairment in the future include reductions in the Corporation's price or margin outlooks, changes in the allocation of capital or development plans, reduced long-term demand for the Corporation's products, and operating cost increases which exceed the pace of efficiencies or the pace of oil and natural gas price or margin increases. However, due to the inherent difficulty in predicting future commodity prices or margins, and the relationship between industry prices and costs, it is not practicable to reasonably estimate the existence or range of any potential future impairment charges related to the Corporation's long-lived assets.

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

Asset Retirement Obligations

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

Suspended Exploratory Well Costs

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

Pension Benefits

The Corporation and its affiliates sponsor about 80 defined benefit (pension) plans in over 40 countries. The Pension and Other Postretirement Benefits footnote (Note 17) provides details on pension obligations, fund assets and pension expense.

Some of these plans (primarily non-U.S.) provide pension benefits that are paid directly by their sponsoring affiliates out of corporate cash flow rather than a separate pension fund because applicable tax rules and regulatory practices do not encourage advance funding. Book reserves are established for these plans. The portion of the pension cost attributable to employee service is expensed as services are rendered. The portion attributable to the increase in pension obligations due to the passage of time is expensed over the term of the obligations, which ends when all benefits are paid. The primary difference in pension expense for unfunded versus funded plans is that pension expense for funded plans also includes a credit for the expected long-term return on fund assets.

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

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

Pension accounting requires explicit assumptions regarding, among others, the long-term expected earnings rate on fund assets, the discount rate for the benefit obligations and the long-term rate for future salary increases. Pension assumptions are reviewed annually by outside actuaries and senior management. These assumptions are adjusted as appropriate to reflect changes in market rates and outlook. The long-term expected earnings rate on U.S. pension plan assets in 2021 was 5.3 percent. The 10-year and 20-year actual returns on U.S. pension plan assets were 9 percent and 7 percent, respectively. The Corporation establishes the long-term expected rate of return by developing a forward-looking, long-term return assumption for each pension fund asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. A worldwide reduction of 0.5 percent in the long-term rate of return on assets would increase annual pension expense by approximately $190 million before tax.

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

Litigation and Tax Contingencies

A variety of claims have been made against the Corporation and certain of its consolidated subsidiaries in a number of pending lawsuits. The Corporation accrues an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and where feasible, an estimate of the possible loss. Management has regular litigation reviews, including updates from corporate and outside counsel, to assess the need for accounting recognition or disclosure of these contingencies. The status of significant claims is summarized in Note 16.

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

The Corporation is subject to income taxation in many jurisdictions around the world. The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. Significant management judgment is required in the accounting for income tax contingencies and tax disputes because the outcomes are often difficult to predict. The Corporation’s unrecognized tax benefits and a description of open tax years are summarized in Note 19.

MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Corporation’s Chief Executive Officer, Chief Financial Officer, and Principal Accounting Officer, is responsible for establishing and maintaining adequate internal control over the Corporation’s financial reporting. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Exxon Mobil Corporation’s internal control over financial reporting was effective as of December 31, 2021.

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

Darren W. Woods
Chief Executive Officer

Kathryn A. Mikells
Senior Vice President and
Chief Financial Officer

Len M. Fox
Vice President and Controller
(Principal Accounting Officer)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Exxon Mobil Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheet of Exxon Mobil Corporation and its subsidiaries (the "Corporation") as of December 31, 2021 and 2020, and the related consolidated statements of income, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2021, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Corporation's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Corporation as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Corporation's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Corporation's consolidated financial statements and on the Corporation's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

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

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

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

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

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

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
February 23, 2022

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

CONSOLIDATED STATEMENT OF INCOME

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

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

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

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

CONSOLIDATED BALANCE SHEET

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

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

CONSOLIDATED STATEMENT OF CASH FLOWS

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

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

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

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

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

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

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

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

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

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

1. Summary of Accounting Policies

Principles of Consolidation and Accounting for Investments

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

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

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

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

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

Revenue Recognition

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

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

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

Income and Other Taxes

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

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

Derivative Instruments

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

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

Fair Value

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

Inventories

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

Property, Plant and Equipment

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

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

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

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

To the extent that proved reserves for a property are substantially de-booked and that property continues to produce such that the resulting depreciation charge does not result in an equitable allocation of cost over the expected life, assets will be depreciated using a unit-of-production method based on reserves determined at the most recent SEC price which results in a more meaningful quantity of proved reserves, appropriately adjusted for production and technical changes.

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

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

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

The Corporation has a robust process to monitor for indicators of potential impairment across its asset groups throughout the year. This process is aligned with the requirements of ASC 360 and ASC 932, and relies in part on the Corporation’s planning and budgeting cycle. Asset valuation analysis, profitability reviews and other periodic control processes assist the Corporation in assessing whether events or changes in circumstances indicate the carrying amounts of any of its assets may not be recoverable.

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

In general, the Corporation does not view temporarily low prices or margins as an indication of impairment. Management believes that prices over the long term must be sufficient to generate investments in energy supply to meet global demand. Although prices will occasionally drop significantly, industry prices over the long term will continue to be driven by market supply and demand fundamentals. On the supply side, industry production from mature fields is declining. This is being offset by investments to generate production from new discoveries, field developments and technology, and efficiency advancements. OPEC investment activities and production policies also have an impact on world oil supplies. The demand side is largely a function of general economic activities, alternative energy sources and levels of prosperity. During the lifespan of its major assets, the Corporation expects that oil and gas prices and industry margins will experience significant volatility, and consequently these assets will experience periods of higher earnings and periods of lower earnings, or even losses. In assessing whether events or changes in circumstances indicate the carrying value of an asset may not be recoverable, the Corporation considers recent periods of operating losses in the context of its longer-term view of prices and margins.

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

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

If events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the Corporation estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. In performing this assessment, assets are grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Cash flows used in recoverability assessments are based on assumptions which are developed in the Corporate Plan, which is reviewed and approved by the Board of Directors, and are consistent with the criteria management uses to evaluate investment opportunities. These evaluations make use of the Corporation's assumptions of future capital allocations, crude oil and natural gas commodity prices including price differentials, refining and chemical margins, volumes, development and operating costs including greenhouse gas emission prices, and foreign currency exchange rates. Volumes are based on projected field and facility production profiles, throughput, or sales. Management's estimate of upstream production volumes used for projected cash flows makes use of proved reserve quantities and may include risk-adjusted unproved reserve quantities. The greenhouse gas emission prices reflect existing or anticipated policy actions that countries or localities may take in support of Paris Accord pledges. Cash flow estimates for impairment testing exclude the effects of derivative instruments.

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

Other Impairments Related to Property, Plant and Equipment. Unproved properties are assessed periodically to determine whether they have been impaired. Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the Corporation's future development plans, the estimated economic chance of success and the length of time that the Corporation expects to hold the properties. Properties that are not individually significant are aggregated by groups and amortized based on development risk and average holding period.

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

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

Environmental Liabilities

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

Foreign Currency Translation

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

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

2. Restructuring Activities

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

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

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

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

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

3. Miscellaneous Financial Information

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

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

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

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

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

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

4. Other Comprehensive Income Information

ExxonMobil Share of Accumulated Other Comprehensive Income	**Cumulative Foreign Exchange Translation Adjustment**	**Postretirement Benefits Reserves Adjustment**	**Total**
		(millions of dollars)	
Balance as of December 31, 2018	(13,881)	(5,683)	(19,564)
Current period change excluding amounts reclassified from accumulated other comprehensive income	1,435	(1,927)	(492)
Amounts reclassified from accumulated other comprehensive income	—	563	563
Total change in accumulated other comprehensive income	1,435	(1,364)	71
Balance as of December 31, 2019	(12,446)	(7,047)	(19,493)
Current period change excluding amounts reclassified from accumulated other comprehensive income *(1)*	1,818	95	1,913
Amounts reclassified from accumulated other comprehensive income	14	861	875
Total change in accumulated other comprehensive income	1,832	956	2,788
Balance as of December 31, 2020	(10,614)	(6,091)	(16,705)
Current period change excluding amounts reclassified from accumulated other comprehensive income *(1)*	(883)	2,938	2,055
Amounts reclassified from accumulated other comprehensive income	(2)	888	886
Total change in accumulated other comprehensive income	(885)	3,826	2,941
Balance as of December 31, 2021	(11,499)	(2,265)	(13,764)

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

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

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

5. Cash Flow Information

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

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

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

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

6. Additional Working Capital Information

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

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

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

7. Equity Company Information

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

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

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

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

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

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

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

8. Investments, Advances and Long-Term Receivables

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

9. Property, Plant and Equipment and Asset Retirement Obligations

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

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

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

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

Asset Retirement Obligations

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

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

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

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

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

10. Accounting for Suspended Exploratory Well Costs

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

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

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

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

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

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

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

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

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

11. Leases

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

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

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

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

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

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

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

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

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

12. Earnings Per Share

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

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

13. Financial Instruments and Derivatives

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

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

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

(1) Included in the Balance Sheet lines: Notes and accounts receivable - net and Other assets, including intangibles - net
(2) Included in the Balance Sheet line: Investments, advances and long-term receivables
(3) Included in the Balance Sheet lines: Investments, advances and long-term receivables and Other assets, including intangibles - net
(4) Included in the Balance Sheet lines: Accounts payable and accrued liabilities and Other long-term obligations
(5) Excluding finance lease obligations
(6) Advances to/receivables from equity companies and long-term obligations to equity companies are mainly designated as hierarchy level 3 inputs. The fair value is calculated by discounting the remaining obligations by a rate consistent with the credit quality and industry of the company.
(7) Included in the Balance Sheet line: Other long-term obligations. Includes contingent consideration related to a prior year acquisition where fair value is based on expected drilling activities and discount rates.

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

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

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

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

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

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

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

14. Long-Term Debt

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

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

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

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

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

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

(1) Average effective interest rate for debt and average imputed interest rate for finance leases at December 31, 2021.
(2) Includes premiums of $131 million in 2021 and $148 million in 2020.
(3) Includes premiums of $82 million in 2021 and $87 million in 2020.

15. Incentive Program

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

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

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

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

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

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

16. Litigation and Other Contingencies

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

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

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

(1) ExxonMobil share.

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

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

17. Pension and Other Postretirement Benefits

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

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

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

(2) Benefit payments for funded and unfunded plans.

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

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

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

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

(1) Benefit payments for funded plans.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

All other postretirement benefit plans are unfunded or underfunded.

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

18. Disclosures about Segments and Related Information

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

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

Earnings after income tax include transfers at estimated market prices.

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

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

Geographic

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

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

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

19. Income and Other Taxes

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

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

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

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

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

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

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

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

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

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

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

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

Unrecognized Tax Benefits. The Corporation is subject to income taxation in many jurisdictions around the world. The benefits of uncertain tax positions that the Corporation has taken or expects to take in its income tax returns are recognized in the financial statements if management concludes that it is more likely than not that the position will be sustained with the tax authorities. For a position that is likely to be sustained, the benefit recognized in the financial statements is measured at the largest amount that is greater than 50 percent likely of being realized. Unrecognized tax benefits reflect the difference between positions taken or expected to be taken on income tax returns and the amounts recognized in the financial statements. The following table summarizes the movement in unrecognized tax benefits:

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

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

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

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

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

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

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

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

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

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

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

Results of Operations	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
2020 - Revenue							
Sales to third parties	2,933	1,034	536	262	1,632	1,983	8,380
Transfers	4,943	3,938	362	4,603	5,584	509	19,939
	7,876	4,972	898	4,865	7,216	2,492	28,319
Production costs excluding taxes	3,877	3,928	786	1,911	1,471	483	12,456
Exploration expenses	51	573	33	371	112	145	1,285
Depreciation and depletion	27,489	5,118	828	2,788	2,171	733	39,127
Taxes other than income	615	106	32	390	692	152	1,987
Related income tax	(5,650)	(944)	(343)	(258)	2,130	241	(4,824)
Results of producing activities for consolidated subsidiaries	(18,506)	(3,809)	(438)	(337)	640	738	(21,712)
Equity Companies							
2020 - Revenue							
Sales to third parties	410	—	513	—	6,289	—	7,212
Transfers	308	—	12	—	60	—	380
	718	—	525	—	6,349	—	7,592
Production costs excluding taxes	500	—	674	6	421	—	1,601
Exploration expenses	—	—	2	—	—	—	2
Depreciation and depletion	605	—	224	—	543	—	1,372
Taxes other than income	34	—	22	—	2,274	—	2,330
Related income tax	—	—	(246)	(1)	1,126	—	879
Results of producing activities for equity companies	(421)	—	(151)	(5)	1,985	—	1,408
Total results of operations	(18,927)	(3,809)	(589)	(342)	2,625	738	(20,304)
Consolidated Subsidiaries							
2019 - Revenue							
Sales to third parties	5,070	1,452	2,141	802	2,393	3,132	14,990
Transfers	6,544	5,979	1,345	7,892	8,706	628	31,094
	11,614	7,431	3,486	8,694	11,099	3,760	46,084
Production costs excluding taxes	4,697	4,366	1,196	2,387	1,597	637	14,880
Exploration expenses	120	498	118	234	119	180	1,269
Depreciation and depletion	5,916	1,975	601	3,019	2,264	703	14,478
Taxes other than income	998	122	113	682	1,182	250	3,347
Related income tax	(29)	(423)	(20)	1,188	4,238	599	5,553
Results of producing activities for consolidated subsidiaries	(88)	893	1,478	1,184	1,699	1,391	6,557
Equity Companies							
2019 - Revenue							
Sales to third parties	664	—	1,248	—	10,536	—	12,448
Transfers	530	—	6	—	464	—	1,000
	1,194	—	1,254	—	11,000	—	13,448
Production costs excluding taxes	543	—	570	6	555	—	1,674
Exploration expenses	1	—	4	—	—	—	5
Depreciation and depletion	431	—	231	—	528	—	1,190
Taxes other than income	33	—	75	—	3,634	—	3,742
Related income tax	—	—	180	(1)	2,275	—	2,454
Results of producing activities for equity companies	186	—	194	(5)	4,008	—	4,383
Total results of operations	98	893	1,672	1,179	5,707	1,391	10,940

Oil and Gas Exploration and Production Costs

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

Capitalized Costs		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
Consolidated Subsidiaries								
As of December 31, 2021								
Property (acreage) costs	– Proved	18,353	3,844	10	1,422	2,994	730	27,353
	– Unproved	21,146	6,231	37	119	5	2,675	30,213
Total property costs		39,499	10,075	47	1,541	2,999	3,405	57,566
Producing assets		101,211	52,092	14,420	56,168	44,228	14,944	283,063
Incomplete construction		4,125	7,047	889	1,428	2,888	2,044	18,421
Total capitalized costs		144,835	69,214	15,356	59,137	50,115	20,393	359,050
Accumulated depreciation and depletion		86,830	28,428	13,790	49,312	26,519	9,225	214,104
Net capitalized costs for consolidated subsidiaries		58,005	40,786	1,566	9,825	23,596	11,168	144,946
Equity Companies								
As of December 31, 2021								
Property (acreage) costs	– Proved	98	—	4	309	—	—	411
	– Unproved	4	—	—	3,111	—	—	3,115
Total property costs		102	—	4	3,420	—	—	3,526
Producing assets		6,946	—	5,487	—	8,676	—	21,109
Incomplete construction		103	—	23	809	11,716	—	12,651
Total capitalized costs		7,151	—	5,514	4,229	20,392	—	37,286
Accumulated depreciation and depletion		4,304	—	5,162	—	6,590	—	16,056
Net capitalized costs for equity companies		2,847	—	352	4,229	13,802	—	21,230
Consolidated Subsidiaries								
As of December 31, 2020								
Property (acreage) costs	– Proved	18,059	2,151	51	1,332	2,979	771	25,343
	– Unproved	23,255	7,352	37	213	181	2,642	33,680
Total property costs		41,314	9,503	88	1,545	3,160	3,413	59,023
Producing assets		104,650	52,552	20,286	55,556	43,394	15,348	291,786
Incomplete construction		5,549	4,590	1,446	1,975	3,050	1,972	18,582
Total capitalized costs		151,513	66,645	21,820	59,076	49,604	20,733	369,391
Accumulated depreciation and depletion		89,401	26,635	19,193	46,567	24,701	8,628	215,125
Net capitalized costs for consolidated subsidiaries		62,112	40,010	2,627	12,509	24,903	12,105	154,266
Equity Companies								
As of December 31, 2020								
Property (acreage) costs	– Proved	98	—	4	286	—	—	388
	– Unproved	4	—	—	3,134	—	—	3,138
Total property costs		102	—	4	3,420	—	—	3,526
Producing assets		6,975	—	5,932	—	8,547	—	21,454
Incomplete construction		138	—	34	721	10,527	—	11,420
Total capitalized costs		7,215	—	5,970	4,141	19,074	—	36,400
Accumulated depreciation and depletion		3,854	—	5,462	—	5,911	—	15,227
Net capitalized costs for equity companies		3,361	—	508	4,141	13,163	—	21,173

Oil and Gas Exploration and Production Costs (continued)

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

Costs Incurred in Property Acquisitions, Exploration and Development Activities		United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total
					(millions of dollars)			
During 2021								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	37	—	—	90	15	—	142
	– Unproved	78	575	—	—	—	35	688
Exploration costs		19	903	46	185	47	40	1,240
Development costs		3,352	2,619	207	389	805	435	7,807
Total costs incurred for consolidated subsidiaries		3,486	4,097	253	664	867	510	9,877
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		—	—	1	—	—	—	1
Development costs		8	—	20	88	1,334	—	1,450
Total costs incurred for equity companies		8	—	21	88	1,334	—	1,451
During 2020								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	1	30	—	344	7	—	382
	– Unproved	80	3	—	47	—	—	130
Exploration costs		60	702	40	232	110	83	1,227
Development costs		5,675	2,059	316	(239)	974	730	9,515
Total costs incurred for consolidated subsidiaries		5,816	2,794	356	384	1,091	813	11,254
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		—	—	2	—	—	—	2
Development costs		135	—	20	71	1,784	—	2,010
Total costs incurred for equity companies		135	—	22	71	1,784	—	2,012
During 2019								
Consolidated Subsidiaries								
Property acquisition costs	– Proved	12	—	—	—	26	—	38
	– Unproved	226	105	1	20	—	—	352
Exploration costs		134	1,107	155	252	111	194	1,953
Development costs		10,275	2,946	809	1,066	1,317	484	16,897
Total costs incurred for consolidated subsidiaries		10,647	4,158	965	1,338	1,454	678	19,240
Equity Companies								
Property acquisition costs	– Proved	—	—	—	—	—	—	—
	– Unproved	—	—	—	—	—	—	—
Exploration costs		1	—	5	—	—	—	6
Development costs		241	—	15	69	2,585	—	2,910
Total costs incurred for equity companies		242	—	20	69	2,585	—	2,916

Oil and Gas Reserves

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

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

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

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

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

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

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

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

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

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

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

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

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

	Crude Oil							Natural Gas Liquids	Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Worldwide	Canada/ Other Americas	Canada/ Other Americas	Total
						(millions of barrels)					
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2019	3,204	529	166	604	3,357	105	7,965	1,404	4,185	466	14,020
Revisions	(677)	(66)	20	(25)	136	—	(612)	(305)	(213)	(27)	(1,157)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	20	—	—	—	—	—	20	12	—	—	32
Sales	(1)	—	(117)	—	—	—	(118)	(27)	—	—	(145)
Extensions/discoveries	710	125	—	—	—	—	835	263	—	—	1,098
Production	(168)	(31)	(30)	(132)	(158)	(11)	(530)	(72)	(114)	(24)	(740)
December 31, 2019	3,088	557	39	447	3,335	94	7,560	1,275	3,858	415	13,108
Attributable to noncontrolling interests		*21*						*3*	*894*	*126*	
Proportional interest in proved reserves of equity companies											
January 1, 2019	254	—	15	6	1,020	—	1,295	342	—	—	1,637
Revisions	15	—	—	—	(38)	—	(23)	3	—	—	(20)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	1	—	—	—	—	—	1	—	—	—	1
Production	(19)	—	(1)	—	(85)	—	(105)	(23)	—	—	(128)
December 31, 2019	251	—	14	6	897	—	1,168	322	—	—	1,490
Total liquids proved reserves at December 31, 2019	3,339	557	53	453	4,232	94	8,728	1,597	3,858	415	14,598
Net proved developed and undeveloped reserves of consolidated subsidiaries											
January 1, 2020	3,088	557	39	447	3,335	94	7,560	1,275	3,858	415	13,108
Revisions	(1,139)	(14)	(9)	19	(20)	(10)	(1,173)	(209)	(3,653)	(79)	(5,114)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	(1)	(2)	—	—	—	—	(3)	(3)	—	—	(6)
Extensions/discoveries	187	1	—	—	—	—	188	65	1	133	387
Production	(176)	(45)	(8)	(110)	(165)	(10)	(514)	(74)	(125)	(25)	(738)
December 31, 2020	1,959	497	22	356	3,150	74	6,058	1,054	81	444	7,637
Attributable to noncontrolling interests		*7*						*1*	*25*	*135*	
Proportional interest in proved reserves of equity companies											
January 1, 2020	251	—	14	6	897	—	1,168	322	—	—	1,490
Revisions	(102)	—	(4)	—	4	—	(102)	(22)	—	—	(124)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	—	—	—	—	—	—	—	—	—
Production	(18)	—	(1)	—	(76)	—	(95)	(23)	—	—	(118)
December 31, 2020	131	—	9	6	825	—	971	277	—	—	1,248
Total liquids proved reserves at December 31, 2020	2,090	497	31	362	3,975	74	7,029	1,331	81	444	8,885

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

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

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

	Crude Oil and Natural Gas Liquids							Bitumen	Synthetic Oil	
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	Canada/ Other Americas	Canada/ Other Americas	Total
					(millions of barrels)					
Proved developed reserves, as of December 31, 2019										
Consolidated subsidiaries	1,655	195	23	419	2,309	90	4,691	3,528	415	8,634
Equity companies	200	—	13	—	727	—	940	—	—	940
Proved undeveloped reserves, as of December 31, 2019										
Consolidated subsidiaries	2,474	381	29	68	1,157	35	4,144	330	—	4,474
Equity companies	60	—	1	6	483	—	550	—	—	550
Total liquids proved reserves at December 31, 2019	4,389	576	66	493	4,676	125	10,325	3,858	415	14,598
Proved developed reserves, as of December 31, 2020										
Consolidated subsidiaries	1,473	293	13	345	2,299	67	4,490	76	311	4,877
Equity companies	111	—	8	—	646	—	765	—	—	765
Proved undeveloped reserves, as of December 31, 2020										
Consolidated subsidiaries	1,342	209	16	42	975	38	2,622	5	133	2,760
Equity companies	24	—	1	6	452	—	483	—	—	483
Total liquids proved reserves at December 31, 2020	2,950	502	38	393	4,372	105	8,360	81	444	8,885
Proved developed reserves, as of December 31, 2021										
Consolidated subsidiaries	1,663	268	3	330	2,154	63	4,481	2,635	326	7,442
Equity companies	133	—	10	—	474	—	617	—	—	617
Proved undeveloped reserves, as of December 31, 2021										
Consolidated subsidiaries	1,621	508	—	31	988	32	3,180	259	112	3,551
Equity companies	28	—	—	5	531	—	564	—	—	564
Total liquids proved reserves at December 31, 2021	3,445	776	13	366	4,147	95	8,842 (1)	2,894	438	12,174

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

Natural Gas and Oil-Equivalent Proved Reserves

	Natural Gas							
	United States	Canada/ Other Americas	Europe	Africa	Asia	Australia/ Oceania	Total	**Oil-Equivalent Total All Products *(1)***
	(billions of cubic feet)							*(millions of oil-equivalent barrels)*
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2019	21,403	1,744	1,312	588	3,841	7,462	36,350	20,078
Revisions	(3,213)	(301)	41	(171)	953	39	(2,652)	(1,599)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	85	—	—	—	—	—	85	47
Sales	(297)	(29)	(416)	—	—	—	(742)	(269)
Extensions/discoveries	2,151	166	—	—	—	—	2,317	1,484
Production	(1,103)	(114)	(316)	(40)	(361)	(500)	(2,434)	(1,145)
December 31, 2019	19,026	1,466	621	377	4,433	7,001	32,924	18,596
Attributable to noncontrolling interests		*256*						
Proportional interest in proved reserves of equity companies								
January 1, 2019	225	—	1,057	863	13,321	—	15,466	4,215
Revisions	(1)	—	(238)	45	142	—	(52)	(29)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—
Extensions/discoveries	1	—	—	—	—	—	1	1
Production	(12)	—	(238)	—	(1,009)	—	(1,259)	(338)
December 31, 2019	213	—	581	908	12,454	—	14,156	3,849
Total proved reserves at December 31, 2019	19,239	1,466	1,202	1,285	16,887	7,001	47,080	22,445
Net proved developed and undeveloped reserves of consolidated subsidiaries								
January 1, 2020	19,026	1,466	621	377	4,433	7,001	32,924	18,596
Revisions	(4,904)	(753)	(4)	(23)	245	(405)	(5,844)	(6,088)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	(35)	(30)	—	—	—	—	(65)	(17)
Extensions/discoveries	433	1	1	—	—	—	435	459
Production	(1,081)	(123)	(177)	(34)	(369)	(462)	(2,246)	(1,113)
December 31, 2020	13,439	561	441	320	4,309	6,134	25,204	11,837
Attributable to noncontrolling interests		*84*						
Proportional interest in proved reserves of equity companies								
January 1, 2020	213	—	581	908	12,454	—	14,156	3,849
Revisions	(99)	—	(95)	9	(106)	—	(291)	(172)
Improved recovery	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—
Sales	—	—	—	—	—	—	—	—
Extensions/discoveries	—	—	—	—	—	—	—	—
Production	(12)	—	(126)	—	(971)	—	(1,109)	(303)
December 31, 2020	102	—	360	917	11,377	—	12,756	3,374
Total proved reserves at December 31, 2020	13,541	561	801	1,237	15,686	6,134	37,960	15,211

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

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

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

Natural Gas and Oil-Equivalent Proved Reserves (continued)

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

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

Standardized Measure of Discounted Future Cash Flows

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

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

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

Standardized Measure of Discounted Future Cash Flows (continued)	United States	Canada/Other Americas *(1)*	Europe	Africa	Asia	Australia/ Oceania	Total
				(millions of dollars)			
Consolidated Subsidiaries							
As of December 31, 2020							
Future cash inflows from sales of oil and gas	93,520	38,193	2,734	15,411	138,080	19,794	307,732
Future production costs	53,635	19,971	1,815	6,527	42,378	3,188	127,514
Future development costs	27,668	10,991	4,244	6,223	13,432	7,580	70,138
Future income tax expenses	(2,509)	851	(1,121)	916	62,223	1,381	61,741
Future net cash flows	14,726	6,380	(2,204)	1,745	20,047	7,645	48,339
Effect of discounting net cash flows at 10%	8,564	1,116	(1,565)	(511)	10,557	3,624	21,785
Discounted future net cash flows	6,162	5,264	(639)	2,256	9,490	4,021	26,554
Equity Companies							
As of December 31, 2020							
Future cash inflows from sales of oil and gas	5,304	—	1,511	740	63,105	—	70,660
Future production costs	3,467	—	694	247	29,170	—	33,578
Future development costs	2,243	—	1,054	163	9,929	—	13,389
Future income tax expenses	—	—	(115)	42	8,088	—	8,015
Future net cash flows	(406)	—	(122)	288	15,918	—	15,678
Effect of discounting net cash flows at 10%	(378)	—	(86)	258	7,443	—	7,237
Discounted future net cash flows	(28)	—	(36)	30	8,475	—	8,441
Total consolidated and equity interests in standardized measure of discounted future net cash flows	6,134	5,264	(675)	2,286	17,965	4,021	34,995
Consolidated Subsidiaries							
As of December 31, 2021							
Future cash inflows from sales of oil and gas	217,023	209,711	4,322	24,812	211,255	69,015	736,138
Future production costs	63,464	111,468	1,142	7,700	55,241	14,880	253,895
Future development costs	29,941	31,736	2,113	5,921	14,519	7,286	91,516
Future income tax expenses	24,770	12,004	451	4,319	107,577	13,038	162,159
Future net cash flows	98,848	54,503	616	6,872	33,918	33,811	228,568
Effect of discounting net cash flows at 10%	50,524	25,793	(502)	739	17,383	18,751	112,688
Discounted future net cash flows	48,324	28,710	1,118	6,133	16,535	15,060	115,880
Equity Companies							
As of December 31, 2021							
Future cash inflows from sales of oil and gas	10,607	—	5,889	4,553	146,845	—	167,894
Future production costs	5,005	—	785	261	49,810	—	55,861
Future development costs	2,340	—	1,137	62	8,317	—	11,856
Future income tax expenses	—	—	1,793	1,168	29,463	—	32,424
Future net cash flows	3,262	—	2,174	3,062	59,255	—	67,753
Effect of discounting net cash flows at 10%	1,553	—	683	1,868	25,710	—	29,814
Discounted future net cash flows	1,709	—	1,491	1,194	33,545	—	37,939
Total consolidated and equity interests in standardized measure of discounted future net cash flows	50,033	28,710	2,609	7,327	50,080	15,060	153,819

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

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

Consolidated and Equity Interests	**2019**		
	Consolidated Subsidiaries	**Share of Equity Method Investees**	**Total Consolidated and Equity Interests**
		(millions of dollars)	
Discounted future net cash flows as of December 31, 2018	106,104	37,572	143,676
Value of reserves added during the year due to extensions, discoveries, improved recovery and net purchases/sales less related costs	(1,252)	4	(1,248)
Changes in value of previous-year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production (lifting) costs	(29,159)	(8,202)	(37,361)
Development costs incurred during the year	16,544	2,927	19,471
Net change in prices, lifting and development costs	(66,455)	(21,046)	(87,501)
Revisions of previous reserves estimates	4,906	657	5,563
Accretion of discount	11,433	3,956	15,389
Net change in income taxes	25,379	6,548	31,927
Total change in the standardized measure during the year	(38,604)	(15,156)	(53,760)
Discounted future net cash flows as of December 31, 2019	67,500	22,416	89,916

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

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

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

INDEX TO EXHIBITS

Exhibit	Description
3(i)	Restated Certificate of Incorporation, as restated November 30, 1999, and as further amended effective June 20, 2001 (incorporated by reference to Exhibit 3(i) to the Registrant's Annual Report on Form 10-K for 2015).
3(ii)	By-Laws, as revised effective March 1, 2020 (incorporated by reference to Exhibit 3(ii) to the Registrant's Report on Form 8-K of March 3, 2020).
4(vi)	Description of ExxonMobil Capital Stock (incorporated by reference to Exhibit 4(vi) to the Registrant's Annual Report on Form 10-K for 2019).
10(iii)(a.1)	2003 Incentive Program, as approved by shareholders May 28, 2003 (incorporated by reference to Exhibit 10(iii)(a.1) to the Registrant's Annual Report on Form 10-K for 2017).*
10(iii)(a.2)	Extended Provisions for Restricted Stock Agreements (incorporated by reference to Exhibit 10(iii)(a.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(a.3)	Extended Provisions for Restricted Stock Unit Agreements – Settlement in Shares.*
10(iii)(b.1)	Short Term Incentive Program, as amended (incorporated by reference to Exhibit 10(iii)(b.1) to the Registrant's Annual Report on Form 10-K for 2018).*
10(iii)(b.2)	Earnings Bonus Unit instrument (incorporated by reference to Exhibit 10(iii)(b.2) to the Registrant's Annual Report on Form 10-K for 2019).*
10(iii)(b.3)	2018 and 2019 Earnings Bonus Unit instruments, as revised effective November 23, 2021 (incorporated by reference to Exhibit 99.1 to the Registrant's Report on Form 8-K of November 30, 2021).*
10(iii)(c.1)	ExxonMobil Supplemental Savings Plan (incorporated by reference to Exhibit 10(iii)(c.1) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2021).*
10(iii)(c.2)	ExxonMobil Supplemental Pension Plan (incorporated by reference to Exhibit 10(iii)(c.2) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2021).*
10(iii)(c.3)	ExxonMobil Additional Payments Plan (incorporated by reference to Exhibit 10(iii)(c.3) to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2021).*
10(iii)(d)	ExxonMobil Executive Life Insurance and Death Benefit Plan (incorporated by reference to Exhibit 10(iii)(d) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.1)	2004 Non-Employee Director Restricted Stock Plan (incorporated by reference to Exhibit 10(iii)(f.1) to the Registrant's Annual Report on Form 10-K for 2018).*
10(iii)(f.2)	Standing resolution for non-employee director restricted grants dated September 26, 2007 (incorporated by reference to Exhibit 10(iii)(f.2) to the Registrant's Annual Report on Form 10-K for 2016).*
10(iii)(f.3)	Form of restricted stock grant letter for non-employee directors.*
10(iii)(f.4)	Standing resolution for non-employee director cash fees dated March 1, 2020 (incorporated by reference to Exhibit 10(iii)(f.4) to the Registrant's Report on Form 10-Q for the quarter ended March 31, 2020).*
14	Code of Ethics and Business Conduct (incorporated by reference to Exhibit 14 to the Registrant's Annual Report on Form 10-K for 2017).
21	Subsidiaries of the registrant.
23	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31.1	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief Executive Officer.
31.2	Certification (pursuant to Securities Exchange Act Rule 13a-14(a)) by Chief 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 Chief Financial Officer.
32.3	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Accounting Officer.
101	Interactive data files (formatted as Inline XBRL).
104	Cover page interactive data file (formatted as Inline XBRL and contained in Exhibit 101).

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

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

SIGNATURES

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

EXXON MOBIL CORPORATION

By: /s/ DARREN W. WOODS
(Darren W. Woods,
Chairman of the Board)

Dated February 23, 2022

POWER OF ATTORNEY

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

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

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

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