Marathon Oil

Dear fellow shareholders,

2019 was another year of differentiated execution for Marathon Oil as we comprehensively delivered on our framework for success for the second year in a row.

We've delivered positive organic free cash flow for eight consecutive quarters, and achieved capital efficiency gains across our portfolio through meaningful reductions in both completed well cost and unit production expenses. We also enhanced our resource base through success across all elements of our comprehensive resource capture framework, adding over three years of inventory through organic enhancement, Resource Play Exploration, and bolt-on acquisitions and trades.

In 2019, we generated $410 million of organic free cash flow post-dividend, and returned that cash back to you, our shareholders. The return of capital to shareholders through the combination of our dividend and share repurchases was entirely funded by free cash flow. Since 2018, we have returned over 20% of our cash from operations to our shareholders and in doing so have reduced our shares outstanding by 7%.

We know that our stakeholders are particularly attuned to environmental, social and governance issues, often referred to as "ESG." Because of this, we've prioritized and improved how we communicate our sustainability work through our annual sustainability report which showcases our efforts to achieve safe, responsible and ethical operations. Last year, we made a commitment to work safer and we succeeded. 2019 marked the best safety performance in MRO history with a peer leading total recordable incident rate (TRIR) of 0.32.

As we turn to 2020 and beyond, Marathon Oil remains committed to this same framework for success. In response to commodity price volatility from simultaneous supply and demand shocks, we're taking swift and decisive action to defend our cash flow generation and protect our balance sheet. We believe our foundational work is already in place with a high quality multi-basin portfolio that affords us flexibility. Our balance sheet reflects a conservative leverage profile and significant liquidity. And, at every level of the Company we continue to strive to relentlessly drive down our cash flow breakeven, while operating safely and responsibly. This framework has served us well, and it positions us to navigate a challenging oil price environment ahead.

Finally, we would like to thank all of our dedicated employees and contractors who made 2019 another year of differentiated execution for our company.

Lee M. Tillman
Chairman, President and
Chief Executive Officer

Gregory H. Boyce
Independent Lead Director

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2019

☐ **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 1-1513

Marathon Oil Corporation

(Exact name of registrant as specified in its charter)

Delaware	**25-0996816**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

5555 San Felipe Street, Houston, Texas 77056-2723
(Address of principal executive offices)

(713) 629-6600
(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, par value $1.00	MRO	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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 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 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 such files). Yes ☑ No ☐

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

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

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

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

The aggregate market value of Common Stock held by non-affiliates as of June 30, 2019: $11,398 million. This amount is based on the closing price of the registrant's Common Stock on the New York Stock Exchange on that date. Shares of Common Stock held by executive officers and directors of the registrant are not included in the computation. The registrant, solely for the purpose of this required presentation, has deemed its directors and executive officers to be affiliates.

There were 795,849,999 shares of Marathon Oil Corporation Common Stock outstanding as of February 14, 2020.

Documents Incorporated By Reference:
Portions of the registrant's proxy statement relating to its 2020 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference to the extent set forth in Part III, Items 10-14 of this report.

MARATHON OIL CORPORATION

Unless the context otherwise indicates, references to "Marathon Oil," "we," "our" or "us" in this Annual Report on Form 10-K are references to Marathon Oil Corporation, including its wholly owned and majority-owned subsidiaries, and its ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest).

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Definitions

Throughout this report, the following company or industry specific terms and abbreviations are used.

AMPCO – Atlantic Methanol Production Company LLC, a company located in Equatorial Guinea in which we own a 45% equity interest.

AMT – Alternative minimum tax.

AOSP – Athabasca Oil Sands Project, an oil sands mining, transportation and upgrading joint venture located in Alberta, Canada, in which we held a 20% non-operated working interest.

bbl – One stock tank barrel, which is 42 United States gallons liquid volume.

boe – Barrels of oil equivalent.

btu – British thermal unit, an energy equivalence measure.

BLM – Bureau of Land Management.

Capital Budget – Includes capital expenditures, cash investments in equity method investees and other investments, exploration costs that are expensed as incurred rather than capitalized, such as geological and geophysical costs and certain staff costs, and other miscellaneous investment expenditures.

CWA – Clean Water Act.

Development Capital Budget – Includes expenditures, investments and costs associated with the Capital Budget excluding resource play exploration (“REx”).

DD&A – Depreciation, depletion and amortization.

Development well – A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry well – A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

E.G. – Equatorial Guinea.

EGHoldings – Equatorial Guinea LNG Holdings Limited, a liquefied natural gas production company located in E.G. in which we own a 60% equity interest.

EPA – United States Environmental Protection Agency.

Exploratory well – A well drilled to find oil or natural gas in an unproved area or find a new reservoir in a field previously found to be productive in another reservoir.

FASB – Financial Accounting Standards Board.

Henry Hub – a natural gas benchmark price quoted at settlement date average.

IRS – United States Internal Revenue Service.

Kurdistan – Kurdistan Region of Iraq.

LIBOR – London Interbank Offered Rate.

LNG – Liquefied natural gas.

LPG – Liquefied petroleum gas.

Liquid hydrocarbons or liquids – Collectively, crude oil, condensate and natural gas liquids.

LLS – Louisiana Light Sweet crude oil, an oil index benchmark price as per Bloomberg Finance LLP: LLS St. James.

MEH – Magellan East Houston, an oil index benchmark price of WTI at Magellan East Houston.

Marathon Oil – Marathon Oil Corporation, including wholly owned and majority-owned subsidiaries, and ownership interests in equity method investees (corporate entities, partnerships, limited liability companies and other ventures over which Marathon Oil exerts significant influence by virtue of its ownership interest). The company as it exists following the June 30, 2011 spin-off of the refining, marketing and transportation operations.

mbbld – Thousand barrels per day.

mboed – Thousand barrels of oil equivalent per day.

mcf – Thousand cubic feet.

mmbbl – Million barrels.

mmboe – Million barrels of oil equivalent. Natural gas is converted on the basis of six mcf of gas per one barrel of crude oil equivalent.

mmbtu – Million British thermal units.

mmcfd – Million stabilized cubic feet per day.

mmta – Million metric tonnes per annum.

mt – Metric tonnes.

mtd – Metric tonnes per day.

NAAQS – National Ambient Air Quality Standard.

Net acres or Net wells – The sum of the fractional working interests owned by us in gross acres or gross wells.

NGL or NGLs – Natural gas liquid or natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline, which can be collectively removed from produced natural gas, separated into these substances and sold.

NYMEX – New York Mercantile Exchange.

OPEC – Organization of Petroleum Exporting Countries.

Operational availability – A term used to measure the ability of an asset to produce to its maximum capacity over a specified period of time, after consideration of internal losses.

Productive well – A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

Proved developed reserves – Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved reserves – Proved crude oil and condensate, NGLs, natural gas and our historical synthetic crude oil reserves are those quantities of crude oil and condensate, NGLs, natural gas and synthetic crude oil, 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, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved undeveloped reserves – Proved reserves 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. Undrilled locations can be classified as having proved undeveloped reserves if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic viability at greater distances.

Reserve replacement ratio – A ratio which measures the amount of proved reserves added to our reserve base during the year relative to the amount of liquid hydrocarbons and natural gas produced.

REx – Resource play exploration.

Royalty interest – An interest in an oil or natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

SAR or SARs – Stock appreciation right or stock appreciation rights.

SCOOP – South Central Oklahoma Oil Province.

SEC – United States Securities and Exchange Commission.

Seismic – An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of subsurface rock formation (3-D seismic provides three-dimensional pictures and 4-D factors in changes that occurred over time).

STACK – Sooner Trend (oil field), Anadarko (basin), Canadian (and) Kingfisher (counties) in Oklahoma.

Total proved reserves – The summation of proved developed reserves and proved undeveloped reserves.

Turnaround – A planned major maintenance program the costs for which are expensed in the period incurred and can include the costs of contractor repair services, materials and supplies, equipment rentals and our labor costs.

U.K. – United Kingdom.

U.S. – United States of America.

U.S. resource plays – Consists of our unconventional properties in the Eagle Ford in Texas, the Bakken in North Dakota, STACK and SCOOP in Oklahoma and Northern Delaware in New Mexico.

U.S. GAAP – U.S. Generally Accepted Accounting Principles.

Working interest – The interest in a mineral property, which gives the owner that share of production from the property. A working interest owner bears that share of the costs of exploration, development and production in return for a share of production. Working interests are sometimes burdened by overriding royalty interests or other interests.

WOTUS – Waters of the United States.

WTI – West Texas Intermediate crude oil, an oil index benchmark price as quoted by NYMEX.

Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation: our operational, financial and growth strategies, including drilling plans and projects, planned wells, rig count, inventory, seismic, exploration plans, maintenance activities, drilling and completion improvements, cost reductions, and financial flexibility; our ability to successfully effect those strategies and the expected timing and results thereof; our 2020 Capital Budget and the planned allocation thereof; planned capital expenditures and the impact thereof; expectations regarding future economic and market conditions and their effects on us; our financial and operational outlook, and ability to fulfill that outlook; our financial position, balance sheet, liquidity and capital resources, and the benefits thereof; resource and asset potential; reserve estimates; growth expectations; and future production and sales expectations, and the drivers thereof. In addition, many forward-looking statements may be identified by the use of forward-looking terminology such as “anticipates,” “believes,” “estimates,” “expects,” “targets,” “plans,” “projects,” “could,” “may,” “should,” “would” or similar words indicating that future outcomes are uncertain. While we believe that our assumptions concerning future events are reasonable, these expectations may not prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to:

- conditions in the oil and gas industry, including supply and demand levels for crude oil and condensate, NGLs and natural gas and the resulting impact on price;
- changes in expected reserve or production levels;
- changes in political or economic conditions in E.G., including changes in foreign currency exchange rates, interest rates, inflation rates, and global and domestic market conditions;
- risks related to our hedging activities;
- liability resulting from litigation;
- capital available for exploration and development;
- the inability of any party to satisfy closing conditions or delays in execution with respect to our asset acquisitions and dispositions;
- drilling and operating risks;
- lack of, or disruption in, access to pipelines or other transportation methods;
- well production timing;
- availability of drilling rigs, materials and labor, including the costs associated therewith;
- difficulty in obtaining necessary approvals and permits;
- non-performance by third parties of their contractual obligations;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts and the governmental or military response thereto;
- cyber-attacks;
- changes in safety, health, environmental, tax and other regulations, or requirements or initiatives including those addressing the impact of global climate change, air emissions or water management;
- other geological, operating and economic considerations; and
- other factors discussed in Item 1. Business, Item 1A. Risk Factors, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and elsewhere in this report.

All forward-looking statements included in this report are based on information available to us on the date of this report. Except as required by law, we undertake no obligation to revise or update any forward-looking statements as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

PART I

Items 1. and 2. Business and Properties

General

Marathon Oil Corporation (NYSE: MRO) is an independent exploration and production company incorporated in 2001, focused on U.S. resource plays: the Eagle Ford in Texas, the Bakken in North Dakota, STACK and SCOOP in Oklahoma and Northern Delaware in New Mexico. We also have international operations in E.G. Our corporate headquarters is located at 5555 San Felipe Street, Houston, Texas 77056-2723 and our telephone number is (713) 629-6600. Each of our two reportable operating segments are organized by geographic location and managed according to the nature of the products and services offered. The two segments are:

- United States – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States;
- International – explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of the United States as well as produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

Our strategy is to deliver competitive and improving corporate level returns by focusing our capital investment in the lower cost, higher margin U.S. resource plays while maintaining a strong balance sheet, prioritizing sustainable cash flow generation over a wide range of commodity prices, and returning capital to shareholders. See **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations**, for a more detailed discussion of our operating results, cash flows and liquidity.

Our portfolio is concentrated in our core operations in the U.S. resource plays and E.G. The map below shows the locations of our U.S. operations:

Segment Information

In the following discussion regarding our United States and International segments, references to net wells, acres, sales or investment indicate our ownership interest or share, as the context requires.

United States Segment

We are engaged in oil and gas exploration, development and production activities in the U.S. Our primary focus in the United States segment is concentrated within our four high-quality resource plays. See **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations** for further detail on current year results.

United States – U.S. Resource Plays

Eagle Ford – We have been operating in the South Texas Eagle Ford play since 2011, where our acreage is located in the high-return Karnes, Atascosa, Gonzales and Lavaca Counties. Our focus is capital efficient development with a goal of maximizing returns and cash flow generation while extending our core acreage. During 2019, we acquired 18,000 net acres adjacent to our existing acreage in the Eagle Ford, which included production of approximately 7,000 net boed and associated midstream infrastructure. Additionally, we operate 32 central gathering and treating facilities across the play that support more than 1,600 producing wells as well as own and operate the Sugarloaf gathering system, a 42-mile natural gas pipeline through the heart of our acreage in Karnes and Atascosa Counties.

Bakken – We have been operating in the Williston Basin since 2006. The majority of our core acreage is within McKenzie, Mountrail, and Dunn Counties in North Dakota targeting the Middle Bakken and Three Forks reservoirs. We continue focusing our investment in our high-return Myrmidon and Hector areas, while also delineating and extending our core acreage across the rest of our position.

Oklahoma – With a history in Oklahoma that dates back more than 100 years, our primary focus has recently been early infill development in the STACK Meramec and SCOOP Woodford, while progressing delineation of other plays across our footprint. We primarily hold net acreage with rights to the Woodford, Springer, Meramec, Osage and other prospect intervals, with a majority of this in the SCOOP and STACK, with our recent activity in these plays being directed towards the more advantaged overpressured oil areas.

Northern Delaware – We have been operating in the Northern Delaware basin, which is located within the greater Permian area, since closing on two major acquisitions in 2017. Our focus has been to strategically advance our position and prepare for future development by further coring up our footprint, progressing early delineation of our acreage, improving our cost structure and securing midstream solutions. We have the majority of our acreage in Eddy and Lea counties primarily in the Wolfcamp and Bone Spring New Mexico plays.

United States – Resource Exploration

Our resource exploration properties in the United States include our acquired acreage in the emerging Louisiana Austin Chalk play, with an acreage position focused in the Western Fairway. Our first exploration well is on flowback and well clean-up and we have recently spud on our second exploration well. We also closed on approximately 40,000 net acres in the Texas Delaware oil play in West Texas for $106 million in 2019.

International Segment

We are engaged in oil and gas development and production activities in E.G. We include the results of our investments in the LPG processing plant, gas liquefaction operations and methanol production operations in E.G. in our International segment.

International

Equatorial Guinea – We own a 63% operated working interest under a production sharing contract in the Alba field and an 80% operated working interest in Block D, both of which are offshore E.G. Operational availability from our company-operated facilities averaged approximately 97% in 2019.

Equatorial Guinea – Gas Processing – We own a 52% interest in Alba Plant LLC, accounted for as an equity method investment, which operates an onshore LPG processing plant located on Bioko Island. Alba field natural gas is processed by the LPG plant under a fixed-price long term contract. The LPG plant extracts secondary condensate and LPG from the natural gas stream and uses some of the remaining dry natural gas in its operations.

We also own 60% of EGHoldings and 45% of AMPCO, both accounted for as equity method investments. EGHoldings operates a 3.7 mmta LNG production facility and AMPCO operates a methanol plant, both located on Bioko Island. These facilities allow us to further monetize natural gas production from the Alba field. The LNG production facility sells LNG under a 3.4 mmta sales and purchase agreement. Under the current agreement, which runs through 2023, the purchaser takes delivery of the LNG on Bioko Island, with pricing linked principally to the Henry Hub index. Gross sales of LNG from this production facility totaled approximately 3 mmta in 2019. AMPCO had gross sales totaling approximately 878 mt in 2019. Methanol production is sold to customers in Europe and the U.S.

During 2019, we executed agreements for third-party gas through existing E.G. infrastructure, the initial step in creating an E.G. gas hub. Natural gas from the Alen field will be processed through the existing Alba Plant LLC LPG processing plant and the EGHoldings LNG production facility. First gas sales are expected in early 2021.

United Kingdom – In the third quarter of 2019, we closed on the sale of our U.K. business, which represents a complete country exit. See Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements for further detail.

Other International

Kurdistan Region of Iraq – In the second quarter of 2019, we closed on the sale of our 15% non-operated interest in the Atrush block in Kurdistan which represents a complete country exit. See Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements for further detail.

Reserves

Proved reserves are required to be disclosed by continent and by country if the proved reserves related to any geographic area, on an oil equivalent barrel basis, represent 15% or more of our total proved reserves. A geographic area can be an individual country, group of countries within a continent or a continent. For additional detail on reserves, see Item 8. Financial Statements and Supplementary Data - **Supplementary Information on Oil and Gas Producing Activities**.

The following tables set forth estimated quantities of our total proved crude oil and condensate, NGLs and natural gas reserves based upon SEC pricing for period ended December 31, 2019.

	Crude Oil and Condensate (mmbbl)	Natural Gas Liquids (mmbbl)	Natural Gas (bcf)	Total (mmboe)	Total (%)
Proved Developed Reserves					
U.S.	304	122	825	563	47%
E.G.	30	19	649	158	13%
Total proved developed reserves (*mmboe*)	334	141	1,474	721	60%
Proved Undeveloped Reserves					
U.S.	315	82	453	473	39%
E.G.	3	2	41	11	1%
Total proved undeveloped reserves (*mmboe*)	318	84	494	484	40%
Total Proved Reserves					
U.S.	619	204	1,278	1,036	86%
E.G.	33	21	690	169	14%
Total proved reserves *(mmboe)*	652	225	1,968	1,205	100%
Total proved reserves (%)	54%	19%	27%	100%	

Productive and Drilling Wells

For our United States and International segments, the following table sets forth gross and net productive wells, service wells and drilling wells as of December 31 for the years presented.

	Productive Wells				Service Wells		Drilling Wells	
	Oil		Natural Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2019								
U.S.	4,984	2,195	1,550	615	204	20	30	15
E.G.	—	—	19	12	—	—	—	—
Total [a]	4,984	2,195	1,569	627	204	20	30	15
2018								
U.S. [b]	4,630	2,056	1,703	655	209	21		
E.G.	—	—	19	12	—	—		
Other International	62	22	11	4	24	8		
Total [c]	4,692	2,078	1,733	671	233	29		
2017								
U.S.	5,132	1,905	1,690	676	799	70		
E.G.	—	—	19	12	—	—		
Libya	1,071	175	7	2	94	16		
Total Africa	1,071	175	26	14	94	16		
Other International	61	22	19	7	23	8		
Total	6,264	2,102	1,735	697	916	94		

(a) Other International was removed from 2019 due to the sale of our U.K. business and our 15% non-operated interest in the Atrush block in Kurdistan. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for further information.

(b) The 2018 decrease in gross productive oil wells and gross service wells is a result of the sale of non-core, non-operated conventional properties in the United States segment during the third quarter of 2018. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for information about these dispositions.

(c) Libya was removed from 2018 due to the sale of our subsidiary in Libya. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for further information.

Drilling Activity

For our United States and International segments, the table below sets forth, by geographic area, the number of net productive and dry development and exploratory wells completed as of December 31 for the years represented.

	Development				Exploratory				
	Oil	Natural Gas	Dry	Total	Oil	Natural Gas	Dry	Total	Total
2019									
U.S.	197	28	—	225	57	26	2	85	310
E.G.	—	—	—	—	—	—	—	—	—
Total [(a)]	197	28	—	225	57	26	2	85	310
2018									
U.S.	171	25	—	196	66	36	2	104	300
E.G.	—	—	—	—	—	—	1	1	1
Other International	—	—	—	—	—	—	—	—	—
Total [(b)]	171	25	—	196	66	36	3	105	301
2017									
U.S.	107	27	—	134	88	16	—	104	238
E.G.	—	—	—	—	—	—	—	—	—
Libya	—	—	—	—	—	—	—	—	—
Total Africa	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	—	—	2	2	2
Total	107	27	—	134	88	16	2	106	240

(a) Other International was removed from 2019 due to the sale of our U.K. business and our 15% non-operated interest in the Atrush block in Kurdistan. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for further information.

(b) Libya was removed from 2018 due to the sale of our subsidiary in Libya. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for further information.

Acreage

We believe we have satisfactory title to our United States and International properties in accordance with standards generally accepted in the industry; nevertheless, we can be involved in title disputes from time to time which may result in litigation. In the case of undeveloped properties, an investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. Our title to properties may be subject to burdens such as royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the industry. In addition, our interests may be subject to obligations or duties under applicable laws or burdens such as net profits interests, liens related to operating agreements, development obligations or capital commitments under international production sharing contracts or exploration licenses.

The following table sets forth, by geographic area, the gross and net developed and undeveloped acreage held as of December 31, 2019.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
U.S.	1,388	993	391	306	1,779	1,299
E.G.	82	67	—	—	82	67
Total	1,470	1,060	391	306	1,861	1,366

In the ordinary course of business, based on our evaluations of certain geologic trends and prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future. If production is not established or we take no other action to extend the terms of the leases, undeveloped acreage listed in the table below could expire over the next three years. We plan to continue the terms of certain of these leases through operational or administrative actions. There are no material quantities of net proved undeveloped reserves assigned to expiring undeveloped acreage in the next three years.

	Net Undeveloped Acres Expiring		
	Year Ended December 31,		
(In thousands)	**2020**	**2021**	**2022**
U.S.	70	108	31
E.G.	—	—	—
Total	70	108	31

Net Sales Volumes are presented on a continuing operations basis. At December 31, 2019, 2018 and 2017, the Eagle Ford, Bakken and Oklahoma fields in the United States contained 15% or more of our total proved reserves. Production for these fields along with our production from fields containing less than 15% of our total proved reserves are presented in the table below.

	December 31,		
	2019	**2018**	**2017**
Net Sales Volumes			
Crude oil and condensate (mbbld) [(a)]			
United States			
Eagle Ford	63	63	59
Bakken	86	71	46
Oklahoma	21	18	15
Northern Delaware	16	12	4
Other U.S.	4	7	9
Africa			
E.G.	15	17	21
Libya	—	7	19
Other International [(b)]	5	15	12
Total	210	210	185
Natural gas liquids (mbbld)			
United States			
Eagle Ford	22	23	21
Bakken	9	7	6
Oklahoma	22	20	14
Northern Delaware	6	4	1
Other U.S.	1	1	1
Africa			
E.G.	9	11	11
Other International [(b)]	—	—	1
Total	69	66	55
Natural gas (mmcfd) [(c)]			
United States			
Eagle Ford	130	129	125
Bakken	46	35	25
Oklahoma	210	213	149
Northern Delaware	36	26	9
Other U.S.	16	26	40
Africa			
E.G.	365	416	459
Libya	—	5	4
Other International [(b)]	6	14	22
Total	809	864	833
Total sales volumes (mboed)			
United States			
Eagle Ford	106	108	101
Bakken	103	84	56
Oklahoma	78	74	54
Northern Delaware	28	20	6
Other U.S.	8	12	17
Africa			
E.G.	85	97	109
Libya	—	8	20
Other International [(b)]	6	17	16
Total	414	420	379

(a) The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.

(b) Other International sales include sales volumes for the U.K. and the Atrush block in Kurdistan, which were both sold in 2019 and sales volumes for the non-operated Sarsang block in Kurdistan which was sold in 2018. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for further information.

(c) Includes natural gas acquired for injection and subsequent resale.

Average Sales Price and Production Costs per Unit are presented on a continuing operations basis by geographic area.

	December 31,		
(Dollars per unit)	2019	2018	2017
Average Sales Price per Unit [(a)]			
Crude oil and condensate (bbl)			
United States	$ 55.80	$ 63.11	$ 49.35
Africa			
E.G.	48.99	55.28	46.02
Libya	—	73.75	60.72
Total Africa	48.99	60.65	53.11
Other International [(b)]	64.71	70.39	52.66
Total	$ 55.54	$ 63.32	$ 50.38
Natural gas liquids (bbl)			
United States	$ 14.22	$ 24.54	$ 20.55
Africa			
E.G. [(d)]	1.00	1.00	1.00
Total Africa	1.00	1.00	1.00
Other International [(b)]	37.88	41.66	39.65
Total	$ 12.46	$ 20.85	$ 16.65
Natural gas (mcf)			
United States	$ 2.18	$ 2.65	$ 2.84
Africa			
E.G. [(c)]	0.24	0.24	0.24
Libya	—	4.57	5.03
Total Africa	0.24	0.30	0.28
Other International [(b)]	5.67	8.03	6.28
Total	$ 1.33	$ 1.58	$ 1.51
Average Production Costs per Unit [(d)]			
U.S.	$ 9.08	$ 9.83	$ 9.49
E.G.	2.34	1.91	2.12
Libya	—	4.35	6.08
Other International [(b)]	30.42	30.02	26.61
Total	$ 8.03	$ 8.68	$ 7.90

(a) Excludes gains or losses on commodity derivative instruments.

(b) Other International sales include sales volumes for the U.K. and the Atrush block in Kurdistan, which were both sold in 2019 and sales volumes for the non-operated Sarsang block in Kurdistan which was sold in 2018. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for further information.

(c) Primarily represents fixed prices under long-term contracts with Alba Plant LLC, AMPCO and/or EGHoldings, which are equity method investees. We include our share of income from each of these equity method investees in our International segment.

(d) Production, severance and property taxes are excluded; however, shipping and handling as well as other operating expenses are included in the production costs used in this calculation. See Item 8. Financial Statements and Supplementary Data – **Supplementary Information on Oil and Gas Producing Activities** - Results of Operations for Oil and Gas Production Activities for more information regarding production costs.

Marketing

Our reportable operating segments include activities related to the marketing and transportation of substantially all of our crude oil and condensate, NGLs and natural gas. These activities include the transportation of production to market centers, the sale of commodities to third parties and the storage of production. We balance our various sales, storage and transportation positions in order to aggregate volumes to satisfy transportation commitments and to achieve flexibility within product types and delivery points. Such activities can include the purchase of commodities from third parties for resale.

Major Customers

We are exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. In 2019, sales to Marathon Petroleum Corporation, Flint Hills Resources, Valero Marketing and Supply, and Shell Trading and each of their respective affiliates, accounted for approximately 13%, 13%, 11% and 10% of our total revenues. In 2018, sales to Valero Marketing and Supply and Flint Hills Resources and their respective affiliates, each accounted for approximately 11% of our total revenues. In 2017, sales to Vitol and their respective affiliates accounted for approximately 10% of our total revenues.

Gross Delivery Commitments

We have committed to deliver gross quantities of crude oil and condensate, NGLs and natural gas to customers under a variety of contracts. As of December 31, 2019, the contracts for fixed and determinable quantities were at variable, market-based pricing and related primarily to the following commitments:

	2020	2021	2022	Thereafter	Commitment Period Through
Eagle Ford					
Crude and condensate *(mbbld)*	51	—	—	—	2020
Natural gas *(mmcfd)*	120	56	36	—	2022
Bakken					
Crude and condensate *(mbbld)*	10	10	10	5 - 10	2027
Natural gas *(mmcfd)*	3	3	3	3 - 25	2028
Other United States					
Natural gas *(mmcfd)*	4	4	1	—	2022

All of these contracts provide the option of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate to satisfy our commitment. In addition to the contracts discussed above, we have entered into numerous agreements for transportation and processing of our equity production. Some of these contracts have volumetric requirements which could require monetary shortfall penalties if our production is inadequate to meet the terms.

Competition

Competition exists in all sectors of the oil and gas industry and we compete with major integrated and independent oil and gas companies, national oil companies, and to a lesser extent, companies that supply alternative sources of energy. We compete, in particular, in the exploration for and development of new reserves, acquisition of oil and natural gas leases and other properties, the marketing and delivery of our production into worldwide commodity markets and for the labor and equipment required for exploration and development of those properties. Principal methods of competing include geological, geophysical, and engineering research and technology, experience and expertise, economic analysis in connection with portfolio management, and safely operating oil and gas producing properties. See **Item 1A. Risk Factors** for discussion of specific areas in which we compete and related risks.

Environmental, Health and Safety Matters

The Health, Environmental, Safety and Corporate Responsibility Committee of our Board of Directors is responsible for overseeing our position on public issues, including environmental, health and safety matters. Our Corporate Health, Environment, Safety and Security organization has the responsibility to ensure that our operating organizations maintain environmental compliance systems that support and foster our compliance with applicable laws and regulations. Committees comprised of certain of our officers review our overall performance associated with various environmental compliance programs. We also have a Corporate Emergency Response Team which oversees our response to any major environmental or other emergency incident involving us or any of our properties.

Our businesses are subject to numerous laws and regulations relating to the protection of the environment, health and safety at the national, state and local levels. These laws and their implementing regulations and other similar state and local laws and rules can impose certain operational controls for minimization of pollution or recordkeeping, monitoring and reporting requirements or other operational or siting constraints on our business, result in costs to remediate releases of regulated substances, including crude oil and produced water, into the environment, or require costs to remediate sites to which we sent regulated substances for disposal. In some cases, these laws can impose strict liability for the entire cost of clean-up on any responsible party without regard to negligence or fault and impose liability on us for the conduct of others (such as prior owners or operators of our assets) or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them. We have incurred and will continue to incur capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations.

New laws have been enacted or are otherwise being considered and regulations are being adopted by various regulatory agencies on a continuing basis and the costs of compliance with these new laws and regulations can only be broadly appraised until their implementation becomes more defined.

For a discussion of environmental capital expenditures and costs of compliance for air, water, solid waste and remediation, see **Item 3. Legal Proceedings** and **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies**.

Air and Climate Change

Environmental advocacy groups and regulatory agencies in the United States and other countries have focused considerable attention on the emissions of carbon dioxide, methane and other greenhouse gases and their role in climate change. Developments in greenhouse gas initiatives may affect us and other similarly situated companies operating in the oil and gas industry. As part of our commitment to environmental stewardship and as required by law, we estimate and publicly report greenhouse gas emissions from our operations. We are working to continuously improve the accuracy and completeness of these estimates. In addition, we continuously strive to improve operational and energy efficiencies through resource and energy conservation where practicable and cost effective.

Government entities and other groups have filed lawsuits in several states and other jurisdictions seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions attributable to those fuels. The lawsuits allege damages as a result of global warming and the plaintiffs are seeking unspecified damages and abatement under various tort theories. Marathon Oil has been named as a defendant in several of these lawsuits, along with numerous other companies. Similar lawsuits may be filed in other jurisdictions. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the claims made against us are without merit and will not have a material adverse effect on our consolidated financial position, results of operations or cash flow.

The EPA finalized a more stringent NAAQS for ozone in October 2015. States that contain any areas designated as non-attainment, and any tribes that choose to do so, will be required to complete development of implementation plans in the 2020-2022 time frame. The EPA may in the future designate additional areas as non-attainment, including areas in which we operate. The EPA is also in the process of reviewing the ozone NAAQS to determine whether to maintain the 2015 standard or to promulgate a more stringent standard. This review is expected to be complete by December 2020. The implementation of the 2015 standard, or the promulgation of a future more stringent standard, may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Although there may be an adverse financial impact (including compliance costs, potential permitting delays and increased regulatory requirements) associated with this revised regulation, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding any additional measures and how they will be implemented. The United States Court of Appeals for the District of Columbia largely upheld EPA's 2015 standard in August 2019. No party has sought review of this decision and, therefore, it is final.

In November 2016, the BLM issued a final rule to further restrict venting and/or flaring of gas from facilities subject to BLM jurisdiction, and to modify certain royalty requirements. BLM issued a two-year stay of these requirements in December 2017. In September 2018, BLM published a final rule to rescind substantial portions of the rule. The rescission was challenged by multiple parties in the U.S. District Court for the Northern District of California. If the judicial challenges to the rule are successful and the rule were to come back into effect, the requirements would result in additional costs of compliance as well as increased monitoring, recordkeeping and recording for some of our facilities.

Hydraulic Fracturing

Hydraulic fracturing is a commonly used process that involves injecting water, sand and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Our business uses this technique extensively throughout our operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. Various state and local-level initiatives in regions with substantial shale resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. Although there may be an adverse financial impact (including compliance costs, potential permitting delays and increased regulatory requirements) associated with these initiatives, the extent and magnitude of that impact cannot be reliably or accurately estimated due to the present uncertainty regarding any additional measures and how they will be implemented.

Water

In 2014, the EPA and the U.S. Army Corps of Engineers published proposed regulations which expand the surface waters that are regulated under the federal CWA and its various programs. While these regulations were finalized largely as proposed in 2015, the rule was stayed by the courts pending a substantive decision on the merits. In October 2019, EPA and the Army Corps of Engineers issued a final rule that repealed the 2015 regulations and reinstated the agencies' narrower pre-2015 scope of federal CWA jurisdiction. In January 2020, EPA and the Army Corp of Engineers promulgated a new WOTUS definition that continues to provide a narrower scope of federal CWA jurisdiction than contemplated under the 2015 WOTUS definition, while also providing for greater predictability and consistency of federal CWA jurisdiction. Judicial challenges to EPA's October 2019 final rule are currently before multiple federal district courts and challenges to EPA's January 2020 final rule are anticipated. If the October 2019 final rule is vacated and the 2015 rule is ultimately implemented, the expansion of CWA jurisdiction will result in additional costs of compliance as well as increased monitoring, recordkeeping and recording for some of our facilities.

For additional information, see **Item 1A. Risk Factors**.

Trademarks, Patents and Licenses

We currently hold U.S. and foreign patents. Although in the aggregate our trademarks and patents are important to us, we do not regard any single trademark, patent, or group of related trademarks or patents as critical or essential to our business as a whole.

Employees

We had approximately 2,000 active, full-time employees as of December 31, 2019.

Information About our Executive Officers

The executive officers of Marathon Oil and their ages as of February 1, 2020, are as follows:

Lee M. Tillman	58	Chairman, President and Chief Executive Officer
Dane E. Whitehead	58	Executive Vice President and Chief Financial Officer
T. Mitch Little	56	Executive Vice President—Operations
Reginald D. Hedgebeth	52	Executive Vice President, General Counsel and Chief Administrative Officer
Patrick J. Wagner	55	Executive Vice President—Corporate Development and Strategy
Gary E. Wilson	58	Vice President, Controller and Chief Accounting Officer

Mr. Tillman was appointed by the board of directors as chairman of the board effective February 1, 2019. In August 2013, he was appointed as president and chief executive officer. Prior to this appointment, Mr. Tillman served as vice president of engineering for ExxonMobil Development Company (a project design and execution company), where he was responsible for all global engineering staff engaged in major project concept selection, front-end design and engineering. Between 2007 and 2010, Mr. Tillman served as North Sea production manager and lead country manager for subsidiaries of ExxonMobil in Stavanger, Norway. Mr. Tillman began his career in the oil and gas industry at Exxon Corporation in 1989 as a research engineer and has extensive operations management and leadership experience.

Mr. Whitehead was appointed executive vice president and chief financial officer in March 2017. Prior to this appointment, Mr. Whitehead served as executive vice president and chief financial officer of both EP Energy Corp. and EP Energy LLC (oil and natural gas producer) since May 2012. Between 2009 and 2012, Mr. Whitehead served as senior vice president of strategy and enterprise business development and a member of El Paso Corporation's executive committee. He joined El Paso Exploration & Production Company as senior vice president and chief financial officer in 2006. Before joining El Paso, Mr. Whitehead was vice president, controller and chief accounting officer of Burlington Resources Inc. (oil and natural gas producer), and formerly senior vice president and CFO of Burlington Resources Canada.

Mr. Little was appointed executive vice president of operations in August 2016 after having served as vice president, conventional since December 2015, vice president international and offshore exploration and production operations since September 2013, and as vice president, international production operations since September 2012. Prior to that, Mr. Little was resident manager of our Norway operations and served as general manager, worldwide drilling and completions. Mr. Little joined Marathon Oil in 1986 and has since held a number of engineering and management positions of increasing responsibility.

Mr. Hedgebeth was appointed executive vice president, general counsel and chief administrative officer in August 2019 after having served as senior vice president, general counsel and secretary since April 2017. Between 2009 and 2017, Mr. Hedgebeth served as general counsel, corporate secretary and chief compliance officer for Spectra Energy Corp (oil and natural gas pipeline company) and general counsel for Spectra Energy Partners, LP. Before joining Spectra Energy, Mr. Hedgebeth served as senior vice president, general counsel and secretary with Circuit City Stores, Inc. (consumer electronics retail company), and vice president of legal for The Home Depot, Inc. (home improvement retail company).

Mr. Wagner was appointed executive vice president of corporate development and strategy in November 2017 after having served as senior vice president of corporate development and strategy since March 2017, vice president of corporate development and interim chief financial officer since August 2016 and vice president of corporate development since April 2014. Prior to this appointment, he served as senior vice president, western business unit, for QR Energy LP (an oil and natural gas producer) and the affiliated Quantum Resources Management, which he joined in early 2012 as vice president, exploitation. Prior to that, Mr. Wagner was managing director in Houston for Scotia Waterous, the oil and gas arm of Scotiabank (an international banking services provider), from 2010 to 2012. Before joining Scotia, Mr. Wagner was vice president, Gulf of Mexico, for Devon Energy Corp. (an oil and natural gas producer), having joined Devon in 2003 as manager, international exploitation.

Mr. Wilson was appointed vice president, controller and chief accounting officer in October 2014. Prior to joining Marathon Oil, he served in various finance and accounting positions of increasing responsibility at Noble Energy, Inc. (a global exploration and production company) since 2001, including as director corporate accounting from February 2014 through September 2014, director global operations services finance from October 2012 through February 2014, director controls and reporting from April 2011 through September 2012, and international finance manager from September 2009 through March 2011.

Available Information

Our website is www.marathonoil.com. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and filings with the SEC are available free of charge on our website as soon as reasonably practicable after the reports are filed or furnished with the SEC. Information contained on our website is not incorporated into this Annual Report on Form 10-K or our other securities filings. Our filings are also available in hard copy, free of charge, by contacting us at 5555 San Felipe Street, Houston, Texas, 77056-2723, Attention: Investor Relations Office, telephone: (713) 629-6600. Additionally, the SEC maintains a website (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Additionally, we make available free of charge on our website:

- our Code of Business Conduct and Code of Ethics for Senior Financial Officers;
- our Corporate Governance Principles; and
- the charters of our Audit and Finance Committee, Compensation Committee, Corporate Governance and Nominating Committee and Health, Environmental, Safety and Corporate Responsibility Committee.

Item 1A. Risk Factors

We are subject to various risks and uncertainties in the course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K.

A substantial decline in crude oil and condensate, NGLs and natural gas prices would reduce our operating results and cash flows and could adversely impact our future rate of growth and the carrying value of our assets.

The markets for crude oil and condensate, NGLs and natural gas have been volatile and are likely to continue to be volatile in the future, causing prices to fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil and condensate, NGLs and natural gas. Many of the factors influencing prices of crude oil and condensate, NGLs and natural gas are beyond our control. These factors include:

- worldwide and domestic supplies of and demand for crude oil and condensate, NGLs and natural gas;
- the cost of exploring for, developing and producing crude oil and condensate, NGLs and natural gas;
- the ability of the members of OPEC and certain non-OPEC members, such as Russia, to agree to and maintain production controls;
- the production levels of non-OPEC countries, including production levels in the shale plays in the United States;
- the level of drilling, completion and production activities by other exploration and production companies, and variability therein, in response to market conditions;
- political instability or armed conflict in oil and natural gas producing regions;
- changes in weather patterns and climate;
- natural disasters such as hurricanes and tornadoes;
- the price and availability of alternative and competing forms of energy, such as nuclear, hydroelectric, wind or solar;
- the effect of conservation efforts;
- epidemics or pandemics;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxes, including further legislation requiring, subsidizing or providing tax benefits for the use of alternative energy sources and fuels; and
- general economic conditions worldwide.

The long-term effects of these and other factors on the prices of crude oil and condensate, NGLs and natural gas are uncertain. Historical declines in commodity prices have adversely affected our business by:

- reducing the amount of crude oil and condensate, NGLs and natural gas that we can produce economically;
- reducing our revenues, operating income and cash flows;
- causing us to reduce our capital expenditures, and delay or postpone some of our capital projects;
- requiring us to impair the carrying value of our assets;
- reducing the standardized measure of discounted future net cash flows relating to crude oil and condensate, NGLs and natural gas; and
- increasing the costs of obtaining capital, such as equity and short- and long-term debt.

Estimates of crude oil and condensate, NGLs and natural gas reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our reserves.

The proved reserve information included in this Annual Report on Form 10-K has been derived from engineering and geoscience estimates. Estimates of crude oil and condensate, NGLs and natural gas were prepared, in accordance with SEC regulations, by our in-house teams of reservoir engineers and geoscience professionals and were reviewed and approved by our Corporate Reserves Group and third-party consultants. Reserves were valued based on SEC pricing for the periods ended December 31, 2019, 2018 and 2017, as well as other conditions in existence at those dates. The table below provides the 2019 SEC pricing for certain benchmark prices:

	2019 SEC Pricing	
WTI Crude oil *(per bbl)*	$	55.69
Henry Hub natural gas *(per mmbtu)*	$	2.58
Brent crude oil *(per bbl)*	$	63.15
Mont Belvieu NGLs *(per bbl)*	$	18.41

If crude oil prices in the future average below prices used to determine proved reserves at December 31, 2019, it could have an adverse effect on our estimates of proved reserve volumes and the value of our business. Future reserve revisions could also result from changes in capital funding, drilling plans and governmental regulation, among other things.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of crude oil and condensate, NGLs and natural gas that cannot be directly measured. Estimates of economically producible reserves and of future net cash flows depend on a number of variable factors and assumptions, including:

- location, size and shape of the accumulation as well as fluid, rock and producing characteristics of the accumulation;
- historical production from the area, compared with production from other analogous producing areas;
- the assumed impacts of regulation by governmental agencies;
- assumptions concerning future operating costs, taxes, development costs and workover and repair costs; and
- industry economic conditions, levels of cash flows from operations and other operating considerations.

As a result, different petroleum engineers and geoscientists, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of proved reserves and future net cash flows based on the same available data. Because of the subjective nature of such reserve estimates, each of the following items may differ materially from the estimated amounts:

- the amount and timing of production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

If we are unsuccessful in acquiring or finding additional reserves, our future crude oil and condensate, NGLs and natural gas production would decline, thereby reducing our cash flows and results of operations and impairing our financial condition.

The rate of production from crude oil and condensate, NGLs and natural gas properties generally declines as reserves are depleted. Except to the extent we acquire interests in additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, optimize production performance or identify additional reservoirs not currently producing or secondary recovery reserves, our proved reserves may decline materially as crude oil and condensate, NGLs and natural gas are produced. Accordingly, to the extent we are not successful in replacing the crude oil and condensate, NGLs and natural gas we produce, our future revenues may decline. Creating and maintaining an inventory of prospects for future production depends on many factors, including:

- obtaining rights to explore for, develop and produce crude oil and condensate, NGLs and natural gas in promising areas;
- drilling success;
- the ability to complete projects timely and cost effectively;
- the ability to find or acquire additional proved reserves at acceptable costs; and

- the ability to fund such activity.

Future exploration and drilling results are uncertain and involve substantial costs.

Drilling for crude oil and condensate, NGLs and natural gas involves numerous risks, including the risk that we may not encounter commercially productive reservoirs. The costs of drilling, completing and operating wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- inflation in exploration and drilling costs;
- fires, explosions, blowouts or surface cratering;
- lack of, or disruption in, access to pipelines or other transportation methods; and
- shortages or delays in the availability of services or delivery of equipment.

If crude oil and condensate, NGLs and natural gas prices decrease, it could adversely affect the abilities of our counterparties to perform their obligations to us which could negatively impact our financial results.

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production, or transportation of crude oil and condensate, NGLs and natural gas, with partners, co-working interest owners, and other counterparties in order to share risks associated with those operations. In addition, we market our products to a variety of purchasers. If commodity prices decrease, some of our counterparties may experience liquidity problems and may not be able to meet their financial and other obligations to us. The inability of our joint venture partners or co-working interest owners to fund their portion of the costs under our joint venture agreements and joint operating agreements, or the nonperformance by purchasers, contractors or other counterparties of their obligations to us, could negatively impact our operating results and cash flows.

If we are unable to complete capital projects at their expected costs and in a timely manner, or if the market conditions assumed in our project economics deteriorate, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Delays or cost increases related to capital spending programs involving drilling and completion activities, engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays or cost increases may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;
- increased costs or operational delays resulting from shortages of water;
- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project’s debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our capital projects.

We may incur substantial capital expenditures and operating costs as a result of compliance with and changes in environmental, health, safety and security law, regulations or requirements or initiatives, including those addressing the impact of global climate change, air emissions or water management, and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Our businesses are currently subject to numerous laws, regulations and other requirements relating to the protection of the environment, including those relating to the discharge of materials into the environment such as the flaring of natural gas, waste management, pollution prevention, greenhouse gas emissions, including carbon dioxide and methane, and the protection of endangered species as well as laws, regulations, and other requirements relating to public and employee safety and health and to facility security. Additionally, states in which we operate may impose additional regulations, legislation, or requirements or begin initiatives addressing the impact of global climate change, air emissions or water management. We have incurred and may continue to incur capital, operating and maintenance, and remediation expenditures as a result of these laws, regulations, and other requirements or initiatives that are being considered or otherwise implemented. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products, our operating results could be adversely affected. The specific impact of these laws, regulations, and other requirements may vary depending on a number of factors, including the age and location of operating facilities and production processes. We may also be required to make material expenditures to modify operations, install pollution control equipment, perform site clean-ups or curtail operations that could materially and adversely affect our business, financial condition, results of operations and cash flows. We may become subject to liabilities that we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws, regulations, and other requirements could result in civil penalties or criminal fines and other enforcement actions against us.

We believe it is likely that the scientific and political attention to issues concerning the extent, causes of and responsibility for climate change will continue, with the potential for further regulations that could affect our operations. Our operations result in greenhouse gas emissions. Currently, various legislative or regulatory measures to address greenhouse gas emissions (including carbon dioxide, methane and nitrous oxides) are in various phases of review, discussion or implementation in the U.S. Internationally, the United Nations Framework Convention on Climate Change finalized an agreement among 195 nations at the 21st Conference of the Parties in Paris with an overarching goal of preventing global temperatures from rising more than 2 degrees Celsius. The agreement includes provisions that every country take some action to lower emissions, but there is no legal requirement for how or by what amount emissions should be lowered. Finalization of new legislation, regulations or international agreements in the future could result in increased costs to operate and maintain our facilities, capital expenditures to install new emission controls at our facilities, and costs to administer and manage any potential greenhouse gas emissions or carbon trading or tax programs. These costs and capital expenditures could be material. Although uncertain, these developments could increase our costs, reduce the demand for crude oil and condensate, NGLs and natural gas, and create delays in our obtaining air pollution permits for new or modified facilities.

The potential adoption of federal, state and local legislative and regulatory initiatives related to hydraulic fracturing could result in increased compliance costs, operating restrictions or delays in the completion of oil and gas wells.

Hydraulic fracturing is a commonly used process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate higher flow of hydrocarbons into the wellbore. Our business uses this technique extensively throughout our U.S. operations. Hydraulic fracturing has been regulated at the state and local level through permitting and compliance requirements. Various state and local-level initiatives in regions with substantial shale resources have been or may be proposed or implemented to further regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. In 2015 the BLM issued a rule governing certain hydraulic fracturing practices on lands within their jurisdiction; however, this rule was rescinded in December 2017. This rescission is being judicially challenged before the U.S. District Court for the Northern District of California.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and condensate, NGLs and natural gas, including from the shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs which could increase costs of our operations and cause considerable delays in acquiring regulatory approvals to drill and complete wells.

The potential adoption of federal, state and local legislative and regulatory initiatives intended to address potential induced seismic activity in the areas in which we operate could result in increased compliance costs, operating restrictions or delays in the completion of oil and gas wells.

State and federal regulatory agencies have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. When caused by human activity, such events are called induced seismicity. Separate and apart from the referenced potential connection between injection wells and seismicity, concerns have been raised that hydraulic fracturing activities may be correlated to anomalous seismic events. Marathon uses hydraulic fracturing techniques throughout its U.S. operations.

While the scientific community and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity, some state regulatory agencies have modified their regulations or guidance to mitigate potential causes of induced seismicity. For example, Oklahoma has taken numerous regulatory actions in response to concerns related to the operation of produced water disposal wells and induced seismicity, and has issued guidelines to operators in certain areas of the State curtailing injection of produced water due to seismic concerns. Marathon does not currently own or operate injection wells or contract for such services in these areas. Further, Oklahoma issued guidelines to operators for management of anomalous seismicity that may be related to hydraulic fracturing activities in the SCOOP/STACK area. In addition, a number of lawsuits have been filed in Oklahoma alleging damage from seismicity relating to disposal well operations. Marathon has not been named in any of those lawsuits.

Increased seismicity in Oklahoma or other areas could result in additional regulation and restrictions on our operations and could lead to operational delays or increased operating costs. Additional regulation and attention given to induced seismicity could also lead to greater opposition, including litigation, to oil and gas activities.

Our offshore operations involve special risks that could negatively impact us.

Offshore operations present technological challenges and operating risks because of the marine environment. Activities in offshore operations may pose risks because of the physical distance to oilfield service infrastructure and service providers. Environmental remediation and other costs resulting from spills or releases may result in substantial liabilities.

Our business could be negatively impacted by cyberattacks targeting our computer and telecommunications systems and infrastructure, or targeting those of our third-party service providers.

Our business, like other companies in the oil and gas industry, has become increasingly dependent on digital technologies, including technologies that are managed by third-party service providers on whom we rely to help us collect, host or process information. Such technologies are integrated into our business operations and used as a part of our production and distribution systems in the U.S. and abroad, including those systems used to transport production to market, to enable communications, and to provide a host of other support services for our business. Use of the internet and other public networks for communications, services, and storage, including “cloud” computing, exposes all users (including our business) to cybersecurity risks.

While we and our third-party service providers commit resources to the design, implementation, and monitoring of our information systems, there is no guarantee that our security measures will provide absolute security. Despite these security measures, we may not be able to anticipate, detect, or prevent cyberattacks, particularly because the methodologies used by attackers change frequently or may not be recognized until launched, and because attackers are increasingly using techniques designed to circumvent controls and avoid detection. We and our third-party service providers may therefore be vulnerable to security events that are beyond our control, and we may be the target of cyber-attacks, as well as physical attacks, which could result in information security breaches and significant disruption to our business. Our information systems and related infrastructure have experienced attempted and actual minor breaches of our cybersecurity in the past, but we have not suffered any losses or breaches which had a material effect on our business, operations or reputation relating to such attacks; however, there is no assurance that we will not suffer such losses or breaches in the future.

As cyberattacks continue to evolve, we may be required to expend significant additional resources to respond to cyberattacks, to continue to modify or enhance our protective measures, or to investigate and remediate any information systems and related infrastructure security vulnerabilities. We may also be subject to regulatory investigations or litigation relating from cybersecurity issues.

Our level of indebtedness may limit our liquidity and financial flexibility.

As of December 31, 2019, our total debt was $5.5 billion, and our next debt maturity is our $1.0 billion 2.8% senior unsecured notes due in 2022. Our indebtedness could have important consequences to our business, including, but not limited to, the following:

- we may be more vulnerable to general adverse economic and industry conditions;
- a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;
- our flexibility in planning for, or reacting to, changes in our industry may be limited;
- a financial covenant in our Credit Agreement stipulates that our total debt to capitalization ratio will not exceed 65% as of the last day of any fiscal quarter, and if exceeded, may make additional borrowings more expensive and affect our ability to plan for and react to changes in the economy and our industry;
- we may be at a competitive disadvantage as compared to similar companies that have less debt; and
- additional financing in the future for working capital, capital expenditures, acquisitions or development activities, general corporate or other purposes may have higher costs and more restrictive covenants.

We may incur additional debt in order to fund our capital expenditures, acquisitions or development activities, or for general corporate or other purposes. A higher level of indebtedness increases the risk that our financial flexibility may deteriorate. Our ability to meet our debt obligations and service our debt depends on future performance. General economic conditions, crude oil and condensate, NGLs and natural gas prices, and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt. See Item 8. Financial Statements and Supplementary Data – **Note 17** to the consolidated financial statements for a discussion of debt obligations.

Difficulty in accessing capital or a significant increase in our costs of accessing capital could adversely affect our business.

We receive debt ratings from the major credit rating agencies in the United States. Due to the volatility in crude oil and U.S. natural gas prices in recent years, credit rating agencies review companies in the energy industry periodically, including us. At December 31, 2019, our corporate credit ratings were: Standard & Poor's Global Ratings Services BBB (stable); Fitch Ratings BBB (stable); and Moody's Investor Services, Inc. Baa3 (stable). The credit rating process is contingent upon a number of factors, many of which are beyond our control. A downgrade of our credit ratings or other influences, including third-party groups promoting the divestment of fossil fuel equities or pressuring financial services companies to limit or curtail activities with fossil fuel companies, could negatively impact our cost of capital and our ability to access the capital markets, increase the interest rate and fees we pay on our revolving credit facility, and may limit or reduce credit lines with our bank counterparties. We could also be required to post letters of credit or other forms of collateral for certain contractual obligations, which could increase our costs and decrease our liquidity or letter of credit capacity under our unsecured revolving credit facility. Limitations on our ability to access capital could adversely impact the level of our capital spending budget, our ability to manage our debt maturities, or our flexibility to react to changing economic and business conditions.

Our commodity price risk management activities may prevent us from fully benefiting from commodity price increases and may expose us to other risks, including counterparty risk.

Global commodity prices are volatile. In order to mitigate commodity price volatility and increase the predictability of cash flows related to the marketing of our crude oil, NGLs, and natural gas, we, from time to time, enter into crude oil, NGLS, and natural gas hedging arrangements with respect to a portion of our expected production. While hedging arrangements are intended to mitigate commodity price volatility, we may be prevented from fully realizing the benefits of price increases above the price levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the counterparties to our hedging contracts fail to perform under the contracts. See **Item 7A. Quantitative and Qualitative Disclosures about Market Risk**.

Political and economic developments and changes in law or policy could adversely affect our operations and materially reduce our profitability and cash flows.

Local political and economic factors in U.S. and global markets could have a material adverse effect on us. We are subject to the political, geographic and economic risks and possible terrorist activities or other armed conflict attendant to doing business within or outside of the U.S. There are also many risks associated with operations in E.G. including the possibility that the government may seize our property with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements or may impose additional taxes or royalty burdens.

Changes in the U.S. or global political and economic environment or any U.S. or global hostility or the occurrence or threat of future terrorist attacks, or other armed conflict, could adversely affect the economies of the U.S. and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. These risks could lead to increased volatility in prices for crude oil and condensate, NGLs and natural gas. In addition, these risks could increase instability in the financial and insurance markets and make it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate. These risks could also cause damage to, or the inability to access, production facilities or other operating assets and could limit our service and equipment providers ability to deliver items necessary for us to conduct our operations.

Actions of governments through tax legislation or interpretations of tax law, and other changes in law, executive order and commercial restrictions could reduce our operating profitability, both in the U.S. and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries and will continue to do so in the future. Changes in U.S. or foreign laws could also adversely affect our results, including new regulations resulting in higher costs to transport our production by pipeline, rail car, truck or vessel or the 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.

Our operations may be adversely affected by pipeline, rail and other transportation capacity constraints.

The marketability of our production depends in part on the availability, proximity, and capacity of gathering and transportation pipeline facilities, rail cars, trucks and vessels. If any pipelines, rail cars, trucks or vessels become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport our crude oil and condensate, NGLs and natural gas, which could increase the costs and/or reduce the revenues we might obtain from the sale of our production. Both the cost and availability of pipelines, rail cars, trucks, or vessels to transport our production could be adversely impacted by new and expected state or federal regulations relating to transportation of crude oil.

If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

We typically seek the acquisition of crude oil and natural gas properties and leases. Although we perform reviews of properties to be acquired in a manner that we believe is diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may they permit us to become sufficiently familiar with the properties in order to fully assess possible deficiencies and potential problems. Even when problems with a property are identified, we often assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. Moreover, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas (as previously discussed), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

We operate in a highly competitive industry, and many of our competitors are larger and have available resources in excess of our own.

The oil and gas industry is highly competitive, and many competitors, including major integrated and independent oil and gas companies, as well as national oil companies, are larger and have substantially greater resources at their disposal than we do. We compete with these companies for the acquisition of oil and natural gas leases and other properties. We also compete with these companies for equipment and personnel, including petroleum engineers, geologists, geophysicists and other specialists, required to develop and operate those properties and in the marketing of crude oil and condensate, NGLs and natural gas to end-users. Such competition can significantly increase costs and affect the availability of resources, which could provide our larger competitors a competitive advantage when acquiring equipment, leases and other properties. They may also be able to use their greater resources to attract and retain experienced personnel.

Many of our major projects and operations are conducted jointly with other parties, which may decrease our ability to manage risk.

We often enter into arrangements to conduct certain business operations, such as oil and gas exploration and production with other parties in order to share risks associated with those operations. However, these arrangements also may decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited influence over and control of the behaviors and performance of these operations. In addition, misconduct, fraud, noncompliance with applicable laws and regulations or improper activities by or on behalf of one or more of our partners or co-working interest owners could have a significant negative impact on our business and reputation.

Our operations are subject to business interruptions and casualty losses. We do not insure against all potential losses and therefore we could be seriously harmed by unexpected liabilities and increased costs.

Our United States and International operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, spills, tornadoes, hurricanes and other adverse weather, tsunamis, earthquakes, volcanic eruptions or nuclear or other disasters, labor disputes and accidents. These same risks can be applied to the third-parties which transport our products from our facilities. A prolonged disruption in the ability of any pipelines, rail cars, trucks, or vessels to transport our production could contribute to a business interruption or increase costs.

Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. These hazards could result in serious personal injury or loss of human life, significant damage to property and equipment, environmental pollution, impairment of operations and substantial losses to us. Various hazards have adversely affected us in the past, and damages resulting from a catastrophic occurrence in the future involving us or any of our assets or operations may result in our being named as a defendant in one or more lawsuits asserting potentially large claims or in our being assessed potentially substantial fines by governmental authorities. We maintain insurance against many, but not all, potential losses or liabilities arising from operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Historically, we have maintained insurance coverage for physical damage including at times resulting business interruption to our major onshore and offshore facilities, with significant self-insured retentions. In the future, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for our insurance policies will change over time and could escalate. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage.

Litigation by private plaintiffs or government officials or entities could adversely affect our performance.

We currently are defending litigation and anticipate that we will be required to defend new litigation in the future. The subject matter of such litigation may include releases of hazardous substances from our facilities, privacy laws, contract disputes, royalty disputes or any other laws or regulations that apply to our operations. In some cases the plaintiff or plaintiffs seek alleged damages involving large classes of potential litigants, and may allege damages relating to extended periods of time or other alleged facts and circumstances. If we are not able to successfully defend such claims, they may result in substantial liability. We do not have insurance covering all of these potential liabilities. In addition to substantial liability, litigation may also seek injunctive relief which could have an adverse effect on our future operations.

For instance, government entities and other groups have filed lawsuits in several states seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions and other alleged harm attributable to those fuels. The lawsuits allege damages as a result of global warming and the plaintiffs are seeking unspecified damages and abatement under various theories. Marathon Oil has been named as a defendant in several of these lawsuits, along with numerous other companies. Similar lawsuits may be filed in other jurisdictions. The ultimate outcome and impact to us cannot be predicted with certainty, and we could incur substantial legal costs associated with defending these and similar lawsuits in the future.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We are a defendant in a number of legal and administrative proceedings arising in the ordinary course of business, including, but not limited to, royalty claims, contract claims, tax disputes and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

See Item 8. Financial Statements and Supplementary Data – **Note 25** to the consolidated financial statements for a description of such legal and administrative proceedings.

Environmental Proceedings

The following is a summary of certain proceedings involving us that were pending or contemplated as of December 31, 2019, under federal and state environmental laws.

Government entities have filed lawsuits in several states seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the greenhouse gas emissions and other alleged harm attributable to those fuels. The lawsuits allege damages as a result of global warming and the plaintiffs are seeking unspecified damages and abatement under various theories. Marathon Oil has been named as a defendant in several of these lawsuits, along with numerous other companies. Similar lawsuits may be filed in other jurisdictions. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe that the claims made against us are without merit and will not have a material adverse effect on our consolidated financial position, results of operations or cash flow.

As of December 31, 2019, we have sites across the country where remediation is being sought under environmental statutes, both federal and state, or where private parties are seeking remediation through discussions or litigation. Based on currently available information the accrued amount to address the clean-up and remediation costs connected with these sites is not material.

In December 2019, we received a Notice of Violation from the North Dakota Department of Environmental Quality and a verbal notice of enforcement in January 2020 from the North Dakota Industrial Commission, related to a release of produced water in North Dakota. In January 2020, we received a Notice of Violation from the EPA related to the Clean Air Act. Each enforcement action will likely result in monetary sanctions in excess of $100,000; however, we do not believe these enforcement actions would have a material adverse effect on our consolidated financial position, results of operations or cash flow.

If our assumptions relating to these costs prove to be inaccurate, future expenditures may exceed our accrued amounts.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The principal market on which Marathon Oil common stock is traded is the New York Stock Exchange ("NYSE"), and is traded under the trading symbol 'MRO'. As of January 31, 2020, there were 28,346 registered holders of Marathon Oil common stock.

Dividends – Our Board of Directors intends to declare and pay dividends on Marathon Oil common stock based on our financial condition and results of operations, although it has no obligation under Delaware law or the restated certificate of incorporation to do so. In determining our dividend policy, the Board of Directors will rely on our consolidated financial statements. Dividends on Marathon Oil common stock are limited to our legally available funds.

The following table provides information about purchases by Marathon Oil and its affiliated purchaser, during the quarter ended December 31, 2019, of equity securities that are registered by Marathon Oil pursuant to Section 12 of the Securities Exchange Act of 1934:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(b)]	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(b)]
10/01/2019 - 10/31/2019	1,619,594	$ 11.65	1,567,951	$ 1,452,022,646
11/01/2019 - 11/30/2019	155,575	$ 11.56	150,386	$ 1,450,286,198
12/01/2019 - 12/31/2019	3,515,651	$ 12.86	3,514,490	$ 1,405,076,614
Total	5,290,820	$ 12.45	5,232,827	

(a) 57,993 shares of restricted stock were delivered by employees to Marathon Oil, upon vesting, to satisfy tax withholding requirements.

(b) In January 2006, we announced a $2 billion share repurchase program. Our Board of Directors subsequently increased the authorization for repurchases under the program by $500 million in January 2007, by $500 million in May 2007, by $2 billion in July 2007, by $1.2 billion in December 2013 and by $950 million in July 2019 for a total authorized amount of $7.2 billion.
Purchases under the program are made at our discretion and may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations, proceeds from potential asset sales or cash from available borrowings to acquire shares. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination by the Board of Directors prior to completion. Shares repurchased as of December 31, 2019 were held as treasury stock.

Item 6. Selected Financial Data

(In millions, except per share data)	Year Ended December 31, 2019	2018	2017	2016	2015
Statement of Income Data[a]					
Total revenues and other income	$ 5,190	$ 6,582	$ 4,765	$ 3,787	$ 4,953
Income (loss) from continuing operations	480	1,096	(830)	(2,087)	(1,701)
Discontinued operations[b]	—	—	(4,893)	(53)	(503)
Net income (loss)	480	1,096	(5,723)	(2,140)	(2,204)
Per Share Data[a]					
Basic:					
Income (loss) from continuing operations	$ 0.59	$ 1.30	$ (0.97)	$ (2.55)	$ (2.51)
Discontinued operations[b]	$ —	$ —	$ (5.76)	$ (0.06)	$ (0.75)
Net income (loss)	$ 0.59	$ 1.30	$ (6.73)	$ (2.61)	$ (3.26)
Diluted:					
Income (loss) from continuing operations	$ 0.59	$ 1.29	$ (0.97)	$ (2.55)	$ (2.51)
Discontinued operations[b]	$ —	$ —	$ (5.76)	$ (0.06)	$ (0.75)
Net income (loss)	$ 0.59	$ 1.29	$ (6.73)	$ (2.61)	$ (3.26)
Statement of Cash Flows Data					
Additions to property, plant and equipment related to continuing operations	$ (2,550)	$ (2,753)	$ (1,974)	$ (1,204)	$ (3,485)
Dividends paid	(162)	(169)	(170)	(162)	(460)
Dividends per share	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.68
Balance Sheet Data at December 31					
Total assets	$ 20,245	$ 21,321	$ 22,012	$ 31,094	$ 32,311
Total long-term debt, including capitalized leases	5,501	5,499	5,494	6,581	7,268
Leases:[c]					
ROU asset	199	—	—	—	—
Current portion of long-term lease liability	101	62	29	30	31
Long-term lease liability	107	155	90	146	147

(a) December 31, 2016 includes the increase of a valuation allowance on certain of our deferred tax assets for $1,346 million.
(b) We closed on the sale of our Canada business in 2017 and have reflected this business as Discontinued Operations in the periods presented.
(c) Note the prospective adoption of the lease accounting standard on January 1, 2019. Therefore, current and long-term portions for leases in years 2018 through 2015 do not reflect adoption of the new lease accounting standard. See Item 8. Financial Statements and Supplementary Data - Note 2 and **Note 13** to the consolidated financial statements for further information.

Supplemental information affecting comparability of selected financial data is shown below.

(In millions)	Year Ended December 31, 2019	2018	2017	2016	2015
Proved property impairment	$ 24	$ 75	$ 229	$ 67	$ 381
Unproved property impairment	98	208	246	195	655
Goodwill impairment	—	—	—	—	340

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data and the other financial information found elsewhere in this Form 10-K. The following discussion includes forward-looking statements that involve certain risks and uncertainties. See "Disclosures Regarding Forward-Looking Statements" (immediately prior to Part I) and ***Item 1A. Risk Factors****.*

Each of our two reportable operating segments are organized by geographic location and managed according to the nature of the products and services offered.

- United States – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States;
- International – explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of the United States and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

Executive Overview

We are an independent exploration and production company based in Houston, Texas. Our strategy is to deliver competitive and improving corporate level returns by focusing our capital investment in the lower cost, higher margin U.S. resource plays (the Eagle Ford in Texas, the Bakken in North Dakota, STACK and SCOOP in Oklahoma and Northern Delaware in New Mexico). We will continue to be guided by maintaining a strong balance sheet, prioritizing sustainable cash flow over a wide range of commodity prices and returning capital to shareholders.

Key 2019 highlights include:

Simplifying and concentrating our portfolio

- In the first quarter of 2019, we closed the sale of our working interest in the Droshky field (Gulf of Mexico) for a pre-tax gain of $42 million.
- In the second quarter of 2019, we closed on the sale of our 15% non-operated interest in the Atrush block in Kurdistan for proceeds of $63 million, before closing adjustments.
- In July 2019, we closed on the sale of our U.K. business for proceeds of approximately $95 million, reflecting the assumption by the buyer of working capital and cash equivalent balances, asset retirement obligations of $966 million, as well as pension obligations.
- In the third quarter of 2019, we secured a 25% non-operated working interest partner in our Louisiana Austin Chalk acreage.
- During the fourth quarter of 2019, we acquired approximately 18,000 net acres in the Eagle Ford for $191 million and approximately 40,000 acres in a Texas Delaware oil play in West Texas for $106 million.

Strengthened balance sheet and liquidity

- In July 2019, the Board of Directors authorized a $950 million increase to our share purchase program. During 2019, we returned additional capital to shareholders by acquiring 24 million of common shares at a cost of $345 million, with $1.4 billion of repurchase authorization remaining at year-end.
- Cash provided by operating activities from continuing operations decreased by 15%, compared to the same period last year, to $2.7 billion primarily as a result of decreased commodity price realizations.
- During the fourth quarter 2019, completed three leverage neutral finance transactions that extend maturities, generate annual cash cost savings, and reflect our commitment to maintaining a strong balance sheet and investment grade credit ratings at all primary rating agencies.

Financial and operational results

- Total net sales volumes for the year were 414 mboed, including 323 mboed in the U.S. Our U.S. net sales volumes increased 8% and our wells to sales increased 11% compared to 2018.
- Added proved reserves of 110 mmboe for a reserve replacement ratio of 74%.
- Our net income per share from continuing operations was $0.59 in 2019 as compared to a net income per share of $1.30 last year. Included in 2019 net income are:
    - A decrease in revenues of approximately 14% compared to 2018, as a result of decreased commodity price realizations and lower net sales volumes in our International segment due to dispositions, partially offset by

increased net sales volumes in the U.S.

- Our net gain on disposal of assets decreased $269 million in 2019 primarily due to the sale of our Libya subsidiary for a pre-tax gain of $255 million in 2018.
- Exploration and impairment expenses decreased by $191 million to $173 million, year over year, primarily a result of non-cash impairment charges on proved and unproved properties in the prior year. See Item 8. Financial Statements and Supplementary Data - Note 11 to the consolidated financial statements for further detail.
- Production expense decreased 15% during 2019 as a result of dispositions in our International segment and our focus on reducing costs in our U.S. resource plays.
- Income tax benefit was $88 million in 2019 primarily as a result of the $126 million settlement of the 2010-2011 U.S. Federal Tax Audit, primarily related to AMT credits. See Consolidated Results of Operations: 2019 compared to 2018 section below and Item 8. Financial Statements and Supplementary Data - **Note 8** and **Note 25** to the consolidated financial statements for further detail.

Outlook

Capital Budget

On February 12, 2020, we announced our total 2020 Capital Budget of $2.4 billion, which includes $2.2 billion of development capital and $200 million to fund REx. Our 2020 development capital budget is weighted towards the four U.S. resource plays with approximately 70% allocated to the Eagle Ford and Bakken and the remaining allocated between the Northern Delaware and Oklahoma.

Our 2020 Capital Budget is broken down by reportable segment in the table below:

(In millions)		**Capital Budget**
United States[(a)]	$	2,370
International and corporate other[(b)]		30
Total Capital Budget	$	2,400

(a) Includes approximately $200 million of spend to fund REx.
(b) International and corporate other includes our International segment and other corporate items.

Operations

Net sales volumes increased by 8% in 2019 in the U.S. segment with new wells to sales across the U.S. resource plays. The International segment had lower net sales volumes in 2019 as a result of dispositions and natural decline in E.G. The following table presents a summary of our sales volumes for each of our segments (refer to the Results of Operations section for a price-volume analysis for each of the segments).

Net Sales Volumes	**2019**	**Increase (Decrease)**	**2018**	**Increase (Decrease)**	**2017**
United States *(mboed)*	323	8 %	298	27 %	234
International *(mboed)*[(a)]	91	(25)%	122	(16)%	145
Total continuing operations *(mboed)*	414	(1)%	420	11 %	379

(a) We closed on the sale of our Libya subsidiary in the first quarter of 2018, our interest in the Atrush block in Kurdistan in the second quarter of 2019 and our U.K. business in the third quarter of 2019. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for further information on dispositions.

United States

Net sales volumes in the segment were higher during the year ended December 31, 2019 primarily as a result of new wells to sales in our U.S. resource plays. The following tables provide additional details regarding net sales volumes, sales mix and operational drilling activity for our significant operations within this segment:

Net Sales Volumes	**2019**	**Increase (Decrease)**	**2018**	**Increase (Decrease)**	**2017**
Equivalent Barrels *(mboed)*					
Eagle Ford	106	(2)%	108	7 %	101
Bakken	103	23 %	84	50 %	56
Oklahoma	78	5 %	74	37 %	54
Northern Delaware	28	40 %	20	233 %	6
Other United States	8	(33)%	12	(29)%	17
Total United States *(mboed)*	323	8 %	298	27 %	234

Sales Mix - U.S. Resource Plays - 2019	**Eagle Ford**	**Bakken**	**Oklahoma**	**Northern Delaware**	**Total**
Crude oil and condensate	59%	84%	27%	58%	59%
Natural gas liquids	21%	9%	28%	20%	18%
Natural gas	20%	7%	45%	22%	23%

Drilling Activity - U.S. Resource Plays	**2019**	**2018**	**2017**
Gross Operated			
Eagle Ford:			
Wells drilled to total depth	127	123	182
Wells brought to sales	146	149	157
Bakken:			
Wells drilled to total depth	73	78	90
Wells brought to sales	105	80	39
Oklahoma:			
Wells drilled to total depth	68	55	86
Wells brought to sales	69	57	73
Northern Delaware:			
Wells drilled to total depth	51	69	27
Wells brought to sales	54	52	18

- *Eagle Ford* – In 2019, our net sales volumes were 106 mboed including oil sales of 63 mbbld. We brought 146 gross company-operated wells to sales across Karnes, Atascosa, and Gonzales counties with strong initial production rates. The third and fourth quarters of 2019 represented the two strongest quarters in the history of the asset on a 30-day initial production basis for oil. Eagle Ford fourth quarter oil mix increased to 63%, up from 57% in the prior-year quarter. Completed well costs during fourth quarter averaged $5.1 million, or 8% below the 2018 average.

- *Bakken* – In 2019, our net sales volumes of 103 mboed with oil sales volume of 86 mbbld. We brought 105 gross company-operated wells to sales in 2019. Fourth quarter 2019 was characterized by strong operations with the asset establishing new quarterly records for both drilling feet per day and completion stages per day. We continue to deliver capital efficiency and accretive financial returns, highlighted by a recent four-well pad in Myrmidon at an average completed well cost of $4.3 million. Wells to sales during the fourth quarter 2019 had an average completed well cost below $5 million, 17% below the 2018 average.

- *Oklahoma* – In 2019, our net sales volumes were 78 mboed including oil sales volumes of 21 mbbld. During the fourth quarter, oil mix rose to 29% in 2019 from 24% in the fourth quarter 2018. We brought 69 gross company-operated wells to sales in 2019, including nine wells targeting the Springer formation in the SCOOP in the fourth quarter 2019. The nine Springer wells are demonstrating solid productivity.

- *Northern Delaware* – Our 2019 net sales volumes were 28 mboed with oil sales volumes of 16 mbbld. We brought 54 gross company-operated wells to sales, with a focus on the delineation of our Red Hills acreage in 2019. Since this transition to Red Hills delineation, we have brought online nine Upper Wolfcamp wells and four Bone Spring wells. We continue to advance learnings, reduce cost structure, and improve margins, exiting the year with about 90% of water and oil on pipe.

International

Net sales volumes in the segment were lower during the year ended December 31, 2019 primarily due to E.G. planned maintenance activities and natural field decline, coupled with the dispositions of our U.K. business and our non-operated interest in the Atrush block in Kurdistan. The following table provides details regarding net sales volumes for our significant operations within this segment:

Net Sales Volumes	**2019**	**Increase (Decrease)**	**2018**	**Increase (Decrease)**	**2017**
Equivalent Barrels *(mboed)*					
Equatorial Guinea	85	(12)%	97	(11)%	109
United Kingdom[a]	5	(62)%	13	(7)%	14
Libya	—	(100)%	8	(60)%	20
Other International	1	(75)%	4	100 %	2
Total International	91	(25)%	122	(16)%	145
Equity Method Investees					
LNG *(mtd)*	4,933	(15)%	5,805	(10)%	6,423
Methanol *(mtd)*	1,082	(13)%	1,241	(10)%	1,374
Condensate and LPG *(boed)*	11,104	(15)%	13,034	(10)%	14,501

[a] Includes natural gas acquired for injection and subsequent resale.

- *Equatorial Guinea* – Net sales volumes in 2019 were lower than 2018 as a result of the planned triennial turnaround completed in 2019 and natural field decline.
- *United Kingdom* – During 2019, we closed on the sale of our U.K. business. See **Note 5** to the consolidated financial statements for further information.
- *Libya* – During the first quarter of 2018, we closed on the sale of our subsidiary in Libya. See **Note 5** to the consolidated financial statements for further information.
- *Equity Method Investees* – Net sales volumes in 2019 are tied to the volumes in Equatorial Guinea which were lower in the current year as noted above.

Market Conditions

Crude oil and condensate and NGLs benchmarks decreased in 2019 as compared to the same period in 2018. As a result, we experienced decreased price realizations associated with those benchmarks. We continue to expect crude oil and condensate, NGLs and natural gas benchmark prices to remain volatile based on global supply and demand, which will result in increases or decreases in our price realizations during 2020. See **Item 1A. Risk Factors** and **Item 7. Management's Discussion and Analysis of Financial Condition – Critical Accounting Estimates** for further discussion of how declines in these commodity prices could impact us.

United States

The following table presents our average price realizations and the related benchmarks for crude oil and condensate, NGLs and natural gas for 2019, 2018 and 2017.

	2019	Increase (Decrease)	2018	Increase (Decrease)	2017
Average Price Realizations[a]					
Crude oil and condensate *(per bbl)*[b]	$ 55.80	(12)%	$ 63.11	28 %	$ 49.35
Natural gas liquids *(per bbl)*	14.22	(42)%	24.54	19 %	20.55
Natural gas *(per mcf)*[c]	2.18	(18)%	2.65	(7)%	2.84
Benchmarks					
WTI crude oil average of daily prices *(per bbl)*	$ 57.04	(12)%	$ 64.90	28 %	$ 50.85
Magellan East Houston ("MEH") crude oil average of daily prices *(per bbl)*[d]	61.96				
LLS crude oil average of daily prices *(per bbl)*[d]			70.04	30 %	54.04
Mont Belvieu NGLs *(per bbl)*[e]	17.81	(33)%	26.75	21 %	22.04
Henry Hub natural gas settlement date average *(per mmbtu)*	2.63	(15)%	3.09	(1)%	3.11

(a) Excludes gains or losses on commodity derivative instruments.
(b) Inclusion of realized gains (losses) on crude oil derivative instruments would have impacted average price realizations by $0.67 per bbl, $(4.60) per bbl, and $0.75 per bbl for 2019, 2018, and 2017.
(c) Inclusion of realized gains (losses) on natural gas derivative instruments would have a minimal impact on average price realizations for the periods presented.
(d) Benchmark change due to industry shift to MEH in the first quarter of 2019.
(e) Bloomberg Finance LLP: Y-grade Mix NGL of 55% ethane, 25% propane, 5% butane, 8% isobutane and 7% natural gasoline.

Crude oil and condensate – Price realizations may differ from benchmarks due to the quality and location of the product.

Natural gas liquids – The majority of our sales volumes are at reference to Mont Belvieu prices.

Natural gas – A significant portion of volumes are sold at bid-week prices, or first-of-month indices relative to our producing areas.

International

The following table presents our average price realizations and the related benchmark for crude oil for 2019, 2018 and 2017.

	2019	Increase (Decrease)	2018	Increase (Decrease)	2017
Average Price Realizations					
Crude oil and condensate *(per bbl)*	$ 53.09	(17)%	$ 64.25	21 %	$ 53.05
Natural gas liquids *(per bbl)*	1.40	(38)%	2.27	(28)%	3.15
Natural gas *(per mcf)*	0.33	(39)%	0.54	(2)%	0.55
Benchmark					
Brent (Europe) crude oil *(per bbl)*[a]	$ 64.36	(9)%	$ 71.06	31 %	$ 54.25

(a) Average of monthly prices obtained from the United States Energy Information Agency website.

United Kingdom

Crude oil and condensate – Generally sold in relation to the Brent crude benchmark. We closed on the sale of our U.K. business on July 1, 2019.

Equatorial Guinea

Crude oil and condensate – Alba Field liquids production is primarily condensate and generally sold in relation to the Brent crude benchmark. Alba Plant LLC processes the rich hydrocarbon gas which is supplied by the Alba Field under a fixed-price long term contract. Alba Plant LLC extracts NGLs and secondary condensate which is then sold by Alba Plant LLC at market prices, with our share of the revenue reflected in income from equity method investments on the consolidated statements of income. Alba Plant LLC delivers the processed dry natural gas to the Alba Field for distribution and sale to AMPCO and EG LNG.

Natural gas liquids – Wet gas is sold to Alba Plant LLC at a fixed-price term contract resulting in realized prices not tracking market price. Alba Plant LLC extracts and keeps NGLs, which are sold at market price, with our share of income from Alba Plant LLC being reflected in the income from equity method investments on the consolidated statements of income.

Natural gas – Dry natural gas, processed by Alba Plant LLC on behalf of the Alba Field, is sold by the Alba Field to EG LNG and AMPCO at fixed-price long term contracts resulting in realized prices not tracking market price. We derive additional value from the equity investment in our downstream gas processing units EG LNG and AMPCO. EG LNG sells LNG on a market-based long term contract and AMPCO markets methanol at market prices.

Consolidated Results of Operations: 2019 compared to 2018

Revenues from contracts with customers are presented by segment in the table below:

	Year Ended December 31,	
(In millions)	2019	2018
Revenues from contracts with customers		
United States	$ 4,602	$ 4,886
International	461	1,016
Segment revenues from contracts with customers	$ 5,063	$ 5,902

Below is a price/volume analysis for each segment. Refer to the preceding **Operations** and **Market Conditions** sections for additional detail related to our net sales volumes and average price realizations.

		Increase (Decrease) Related to		
(In millions)	Year Ended December 31, 2018	Price Realizations	Net Sales Volumes	Year Ended December 31, 2019
United States Price/Volume Analysis				
Crude oil and condensate	$ 3,947	$ (510)	$ 450	$ 3,887
Natural gas liquids	495	(223)	35	307
Natural gas	413	(75)	11	349
Other sales	31			59
Total	$ 4,886			$ 4,602
International Price/Volume Analysis				
Crude oil and condensate	$ 888	$ (83)	$ (407)	$ 398
Natural gas liquids	9	(3)	(1)	5
Natural gas	86	(29)	(13)	44
Other sales	33			14
Total	$ 1,016			$ 461

Net loss on commodity derivatives increased $58 million in 2019 from 2018. We have multiple crude oil and natural gas derivative contracts indexed to NYMEX WTI and Henry Hub. We record commodity derivative gains/losses as the respective index pricing and forward curves change each period. See **Note 15** to the consolidated financial statements for further information.

Income from equity method investments decreased $138 million as a result of lower price realizations and lower net sales volumes due to the 2019 triennial turnaround in E.G. and natural decline of the Alba field which resulted in lower net sales volumes for equity method investments.

Net gain on disposal of assets decreased $269 million in 2019 from 2018. This decrease was primarily related to the 2018 sale of our Libya subsidiary for a pre-tax gain of $255 million. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for information about these dispositions.

Other income decreased $88 million in 2019 from 2018 primarily due to the 2018 reduction of our U.K. asset retirement obligation, versus the 2019 indemnification of certain tax liabilities in connection with the closure of the 2010-2011 Federal Tax Audit with the IRS. This indemnity relates to tax and interest allocable to MPC as a result of the IRS Audit in accordance with the Tax Sharing Agreement. See Item 8. Financial Statements and Supplementary Data - **Note 8** to the consolidated financial statements for detail about our asset retirement obligation.

Production expenses decreased $130 million during 2019 from 2018. The International segment decreased $89 million primarily due to dispositions, which included the sale of our U.K. business on July 1, 2019. Our United States segment decreased $37 million primarily due to reduced water hauling costs with more water on pipe in the Northern Delaware and non-core asset dispositions in the Gulf of Mexico during 2018, slightly offset by increased water handling in Bakken due to more producing wells in 2019 than in 2018.

The production expense rate (per boe) declined during 2019 in the United States as a result of continued focus on cost reduction as well as higher net sales volumes.

The following table provides production expense and production expense rates for each segment:

(In millions/$ per boe)	2019	2018	Increase (Decrease)	2019	2018	Increase (Decrease)
Production Expense and Production Expense Rate		**Expense**			**Rate**	
United States	$ 588	$ 625	(6)%	$ 4.98	$ 5.75	(13)%
International	$ 126	$ 215	(41)%	$ 3.76	$ 4.86	(23)%

Shipping, handling and other operating expenses increased $30 million in 2019 from 2018 primarily as a result of increased sales volumes in our United States segment, partially offset by the sale of our U.K. business in the International segment.

Exploration expenses decreased $140 million during 2019 versus the comparable 2018. Decreases in unproved property impairments were driven by changes in impairment assumptions based on actual development experience. Also in 2018, there was $32 million of dry well costs and $16 million in unproved property impairments related to the Rodo well in Alba Block Sub Area B, offshore E.G. See Item 8. Financial Statements and Supplementary Data - **Note 11** to the consolidated financial statements for details of these items.

The following table summarizes the components of exploration expenses:

	Year Ended December 31,		
(In millions)	2019	2018	Increase (Decrease)
Exploration Expenses			
Unproved property impairments	$ 98	$ 208	(53)%
Dry well costs	16	47	(66)%
Geological and geophysical	18	21	(14)%
Other	17	13	31 %
Total exploration expenses	$ 149	$ 289	(48)%

Depreciation, depletion and amortization decreased $44 million in 2019 from 2018 primarily as a result of dispositions which included the sale of our U.K. business and the sale of certain non-core asset dispositions in our United States segment. Adding to the decrease were lower 2019 production volumes in E.G. Our segments apply the units-of-production method to the majority of their assets, including capitalized asset retirement costs; therefore, volumes have an impact on DD&A expense.

The DD&A rate (per boe), which is impacted by field-level changes in reserves, capitalized costs and sales volumes, can also impact our DD&A expense. The DD&A rate for International decreased primarily as a result of dispositions. Our United States DD&A rate decreased in 2019 primarily due to reserve additions as well as non-core asset dispositions in 2018.

The following table provides DD&A expense and DD&A expense rates for each segment:

(In millions/$ per boe)	2019	2018	Increase (Decrease)	2019	2018	Increase (Decrease)
DD&A Expense and DD&A Expense Rate	**Expense**			**Rate**		
United States	$ 2,250	$ 2,217	1 %	$ 19.07	$ 20.39	(6)%
International	$ 121	$ 197	(39)%	$ 3.61	$ 4.44	(19)%

Impairments decreased $51 million in 2019 from 2018 as a result of lower anticipated sales of certain non-core proved properties in our International and United States segments in the current period. See Item 8. Financial Statements and Supplementary Data - **Note 11** to the consolidated financial statement for detail of proved property impairments each year.

General and administrative expenses decreased $38 million in 2019 compared to 2018. This was primarily the result of decreased compensation costs.

Provision (benefit) for income taxes reflects an effective tax benefit rate of 22% for 2019, as compared to an effective income tax expense rate of 23% for 2018. See Item 8. Financial Statements and Supplementary Data - **Note 8** to the consolidated financial statements for a discussion of the effective income tax rate.

Segment Results: 2019 compared to 2018

Segment Income

Segment income represents income which excludes certain items not allocated to our operating segments, net of income taxes. A portion of our corporate and operations general and administrative support costs are not allocated to the operating segments. These unallocated costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities. Additionally, items which affect comparability such as: gains or losses on dispositions, certain property impairments, certain exploration expenses relating to a strategic decision to exit conventional exploration, unrealized gains or losses on commodity derivative instruments, pension settlement losses or other items (as determined by the CODM) are not allocated to operating segments.

The following table reconciles segment income to net income:

	Year Ended December 31,		
(In millions)	2019	2018	Increase (Decrease)
United States	$ 675	$ 608	11 %
International	233	473	(51)%
Segment income	908	1,081	(16)%
Items not allocated to segments, net of income taxes[a]	(428)	15	(2,953)%
Net income	$ 480	$ 1,096	(56)%

[a] See Item 8. Financial Statements and Supplementary Data - **Note 7** to the consolidated financial statements for further detail about items not allocated to segments.

United States segment income increased $67 million after-tax in 2019 compared to 2018 primarily due to a net gain on commodity derivatives in 2019 versus net loss on commodity derivatives in 2018, as well as lower exploration costs. This increase was partially offset by lower price realizations along with increases in certain expenses as a result of higher net sales volumes.

International segment income decreased $240 million after-tax in 2019 compared to 2018 primarily due to lower income from our equity method investments and our operations in E.G. as a result of lower sales volumes and price realizations, offset by lower costs and taxes due to dispositions. Sales volumes decreased due to the planned triennial turnaround in E.G. completed in the first quarter 2019 and natural field decline in E.G. The income decrease was also attributed to dispositions of our U.K. business and our non-operated interest in the Atrush block in Kurdistan.

Consolidated Results of Operations: 2018 compared to 2017

A detailed discussion of the year-over-year changes from the year ended December 31, 2018 to December 31, 2017 can be found in the Management's Discussion and Analysis section of our Annual Report on Form 10-K for the year ended December 31, 2018.

Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

Commodity prices are the most significant factor impacting our operating cash flows and the amount of capital available to reinvest into the business. In 2019, we experienced a decrease in operating cash flows primarily as a result of lower commodity realizations, of which crude oil and condensate price realizations decreased by 12% to $55.54 per barrel.

During 2019 our cash flow highlights include:

- We returned capital to shareholders by executing $345 million of share repurchases along with $162 million in dividend payments.
- Asset acquisitions during the year of $293 million were paid with cash on hand.
- Cash and cash equivalents decreased $604 million to $858 million at December 31, 2019.
- During the fourth quarter, we completed three leverage neutral finance transactions which extend maturities and generate annual cash savings.

At December 31, 2019, we had approximately $3.9 billion of liquidity consisting of $858 million in cash and cash equivalents and $3.0 billion available under our revolving credit facility. In September 2019, we entered into an amendment to our Credit Facility to reduce the maximum borrowing from $3.4 billion to $3.0 billion and extended the maturity date by one year to May 28, 2023. As previously discussed in the Outlook section, we are targeting a $2.4 billion Capital Budget for 2020. We believe our current liquidity level, cash flow from operations and ability to access the capital markets provides us with the flexibility to fund our business across a wide range of commodity price environments.

Cash Flows

The following table presents sources and uses of cash and cash equivalents for 2019 and 2018:

	Year Ended December 31,			
(In millions)		2019		2018
Sources of cash and cash equivalents				
Operating activities	$	2,749	$	3,234
Disposal of assets, net of cash transferred to the buyer		(76)		1,264
Borrowings		600		—
Other		65		93
Total sources of cash and cash equivalents	$	3,338	$	4,591
Uses of cash and cash equivalents				
Additions to property, plant and equipment	$	(2,550)	$	(2,753)
Additions to other assets		36		(26)
Acquisitions, net of cash acquired		(293)		(25)
Purchases of common stock		(362)		(713)
Debt repayments		(600)		—
Dividends paid		(162)		(169)
Other		(11)		(6)
Total uses of cash and cash equivalents	$	(3,942)	$	(3,692)

Cash flows generated from operating activities in 2019 were 15% lower as commodity price realizations decreased 13% along with lower net sales volumes in our International segment as a result of E.G. planned maintenance and natural field decline, coupled with dispositions.

Disposals of assets in 2019 were primarily related to proceeds, net of the cash transferred to the buyer, with the sale of our U.K. business; partially offset by the proceeds received from the sale of a 25% non-operated working interest in the Louisiana Austin Chalk as well as the sale of our non-operated interest in the Atrush block in Kurdistan. Proceeds from the disposals of assets for 2018 are primarily related to our non-operated interest in Libya, as well as the remaining proceeds from the sale of our Canadian business. Disposition transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements.

Additions to property, plant and equipment in 2019 totaled $2.6 billion, consistent with expectations (last year, we communicated our $2.6 billion Capital Budget consisted of $2.4 billion in development capital and $200 million to fund resource play exploration.

The following table shows capital expenditures by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows:

	Year Ended December 31,	
(In millions)	**2019**	**2018**
United States [a]	$ 2,550	$ 2,620
International	16	39
Corporate	25	26
Total capital expenditures	2,591	2,685
Change in capital expenditure accrual[a]	(41)	68
Total use of cash and cash equivalents for property, plant and equipment	$ 2,550	$ 2,753

[a] The change in capital expenditure accrual includes activity for assets classified as held for sale for the years presented.

Additions to other assets relates to deposits on our resource play exploration program.

In the fourth quarter 2019, we acquired approximately 18,000 net acres in the Eagle Ford for $191 million and approximately 40,000 acres in a Texas Delaware oil play in West Texas for $106 million.

During the fourth quarter 2019, we completed two separate financing transactions resulting in a debt borrowing of $600 million and debt repayment of $600 million, which is further discussed in the Capital Resources section below. Also see Item 8. Financial Statements and Supplementary Data - **Note 17** to the consolidated financial statements for details of these items

During 2019 and 2018, the Board of Directors approved a $0.05 per share quarterly dividend. See Capital Requirements below for additional information about the fourth quarter 2019 dividend.

Available Liquidity

In September 2019, we entered into an amendment to our Credit Facility to reduce the maximum borrowing from $3.4 billion to $3.0 billion and extended the maturity date by one year to May 28, 2023.

Our main sources of liquidity are cash and cash equivalents, internally generated cash flow from operations, sales of non-core assets, capital market transactions, and our revolving Credit Facility. At December 31, 2019, we had approximately $3.9 billion of liquidity consisting of $858 million in cash and cash equivalents and $3.0 billion available under our revolving Credit Facility. Our working capital requirements are supported by these sources and we may issue either commercial paper backed by our revolving Credit Facility or draw on our revolving credit facility to meet short-term cash requirements, or issue debt or equity securities through the shelf registration statement discussed below as part of our longer-term liquidity and capital management program. Because of the alternatives available to us as discussed above, we believe that our short-term and long-term liquidity are adequate to fund not only our current operations, but also our near-term and long-term funding requirements including our capital spending programs, dividend payments, defined benefit plan contributions, repayment of debt maturities, and other amounts that may ultimately be paid in connection with contingencies.

General economic conditions, commodity prices, and financial, business and other factors could affect our operations and our ability to access the capital markets. Our corporate credit ratings as of December 31, 2019 are: Standard & Poor's Ratings Services BBB (stable); Fitch Ratings BBB (stable); and Moody's Investor Services, Inc. Baa3 (stable). We are rated investment grade at all three primary credit rating agencies. In addition, we also have the ability to borrow on our U.S. commercial paper program, which is backed by the revolving credit facility. A downgrade in our credit ratings could increase our future cost of financing or limit our ability to access capital, and result in additional collateral requirements. See **Item 1A. Risk Factors** for a discussion of how a downgrade in our credit ratings could affect us.

We may incur additional debt in order to fund our capital expenditures, acquisitions or development activities, or for general corporate or other purposes. A higher level of indebtedness could increase the risk that our liquidity and financial flexibility deteriorates. See **Item 1A. Risk Factors** for a further discussion of how our level of indebtedness could affect us.

Capital Resources

Credit Arrangements and Borrowings

At December 31, 2019, we had no borrowings against our Credit Facility or under our U.S. commercial paper program that is backed by the Credit Facility.

At December 31, 2019, we had $5.5 billion in long-term debt outstanding. We do not have any triggers on any of our corporate debt that would cause an event of default in the case of a downgrade of our credit ratings.

On October 1, 2019, we closed a $600 million remarketing to investors of sub-series A bonds which are part of the $1.0 billion St. John the Baptist, State of Louisiana revenue refunding bonds originally issued and purchased in December 2017. The $600 million in proceeds from the conversion and remarketing were used to pay the purchase price of our converted 2017 bonds on the closing date. We continue to own the remaining $400 million of the revenue refunding bonds and have the right to convert and remarket them to investors at any time up to the 2037 maturity date.

On October 3, 2019, we redeemed our $600 million 2.7% senior unsecured notes due June 2020. Our next debt maturity is the $1.0 billion 2.8% senior unsecured notes due 2022.

Shelf Registration

We have a universal shelf registration statement filed with the SEC under which we, as a "well-known seasoned issuer" for purposes of SEC rules, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Asset Disposals

In the third quarter of 2019, we closed on the sale of our U.K. business for proceeds of approximately $95 million, reflecting the assumption by the buyer of working capital and cash equivalent balances, asset retirement obligations of $966 million, as well as the pension obligations.

In the second quarter of 2019, we closed on the sale of our 15% non-operated interest in the Atrush block in Kurdistan for proceeds of $63 million, before closing adjustments. Disposition transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements.

Debt-To-Capital Ratio

The Credit Facility includes a covenant requiring that our ratio of total debt to total capitalization not exceed 65% as of the last day of each fiscal quarter. Our debt-to-capital ratio was 31% at both December 31, 2019 and 2018.

Capital Requirements

Capital Spending

Our approved Capital Budget for 2020 is $2.4 billion. Additional details were previously discussed in **Outlook**.

Share Repurchase Program

In 2019, we acquired approximately 24 million common shares at a cost of $345 million under our share repurchase program with remaining share repurchase authorization as of December 31, 2019 of $1.4 billion.

Other Expected Cash Outflows

On January 29, 2020, our Board of Directors approved a dividend of $0.05 per share for the fourth quarter of 2019. The dividend is payable on March 10, 2020 to shareholders of record on February 19, 2020.

We plan to make contributions of up to $28 million to our funded pension plans during 2020. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $6 million and $18 million in 2020.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2019.

(In millions)	Total	2020	2021-2022	2023-2024	Later Years
Short and long-term debt (includes interest)[(a)]	$ 8,320	$ 252	$ 1,538	$ 1,016	$ 5,514
Lease obligations[(b)]	276	114	98	6	58
Purchase obligations:					
Oil and gas activities[(c)]	52	42	2	1	7
Service and materials contracts[(d)]	126	69	54	3	—
Transportation and related contracts	1,872	225	520	476	651
Other [(e)]	33	29	4	—	—
Total purchase obligations	2,083	365	580	480	658
Other long-term liabilities reported in the consolidated balance sheet[(f)]	410	32	52	48	278
Total contractual cash obligations[(g)]	$ 11,089	$ 763	$ 2,268	$ 1,550	$ 6,508

(a) Includes anticipated cash payments for interest of $252 million for 2020, $503 million for 2021-2022, $415 million for 2023-2024 and $1.6 billion for the remaining years for a total of $2.8 billion.

(b) Includes project costs incurred as of December 31, 2019 for new build-to-suit office building in Houston, Texas. See Item 8. Financial Statements and Supplementary Data – **Note 13** to the consolidated financial statements and Off-Balance Sheet Arrangements section below.

(c) Oil and gas activities include contracts to acquire property, plant and equipment and commitments for oil and gas exploration such as costs related to contractually obligated exploratory work programs that are expensed immediately.

(d) Service and materials contracts include contracts to purchase services such as utilities, supplies and various other maintenance and operating services.

(e) Includes any drilling rigs and fracturing crews that are not considered lease obligations.

(f) Primarily includes obligations for pension and other postretirement benefits including medical and life insurance. We have estimated projected funding requirements through 2027. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

(g) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $254 million. See Item 8. Financial Statements and Supplementary Data – **Note 12** to the consolidated financial statements.

Transactions with Related Parties

We own a 63% working interest in the Alba field offshore E.G. Onshore E.G., we own a 52% interest in an LPG processing plant, a 60% interest in an LNG production facility and a 45% interest in a methanol production plant, each through equity method investees. We sell our natural gas from the Alba field to these equity method investees as the feedstock for their production processes.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements comprise those arrangements that may potentially impact our liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under accounting principles generally accepted in the U.S. Although off-balance sheet arrangements serve a variety of our business purposes, we are not dependent on these arrangements to maintain our liquidity and capital resources, and we are not aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on liquidity and capital resources.

We will issue stand-alone letters of credit when required by a business partner. Such letters of credit outstanding at December 31, 2019, 2018 and 2017 aggregated $14 million, $52 million and $89 million. Most of the letters of credit are in support of obligations recorded in the consolidated balance sheet. In 2019, our letters of credit outstanding decreased as a result of our upgraded credit rating and the sale of our U.K. business (we no longer have requirements to support firm transportation agreements and future abandonment liabilities).

In 2018, we signed an agreement with an owner/lessor to construct and lease a new build-to-suit office building in Houston, Texas. The new Houston office location is expected to be completed in 2021. The lessor and other participants are providing financing for up to $380 million, to fund the estimated project costs. As of December 31, 2019 project costs incurred totaled $58 million, primarily for land acquisition and initial design costs. The initial lease term is five years and will commence once construction is substantially complete and the new Houston office is ready for occupancy. At the end of the initial lease term, we can extend the term of the lease for an additional five years, subject to the approval of the participants; purchase the property subject to certain terms and conditions; or remarket the property to an unrelated third party. The lease contains a residual value guarantee of approximately 89% of the total acquisition and construction costs. See Item 8. Financial Statements and Supplementary Data – **Note 13** to the consolidated financial statements for further information on leases.

Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies

We have incurred and will continue to incur capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately offset by the prices of our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

We accrue for environmental remediation activities when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. As environmental remediation matters proceed toward ultimate resolution or as additional remediation obligations arise, charges in excess of those previously accrued may be required.

New or expanded environmental requirements, which could increase our environmental costs, may arise in the future on both state and federal levels. We strive to comply with all legal requirements regarding the environment, but as not all costs are fixed or presently determinable (even under existing legislation) and may be affected by future legislation or regulations, it is not possible to predict all of the ultimate costs of compliance, including remediation costs that may be incurred and penalties that may be imposed.

For more information on environmental regulations that impact us, or could impact us, see **Item 1. Business – Environmental, Health and Safety Matters**, **Item 1A. Risk Factors** and **Item 3. Legal Proceedings**.

Critical Accounting Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the U.S. requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Estimated Quantities of Net Reserves

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved crude oil and condensate, NGLs and natural gas reserves. The amount of estimated proved reserve volumes affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depreciated, depleted or amortized into net income and the presentation of supplemental information on oil and gas producing activities. In addition, the expected future cash flows to be generated by producing properties are used for testing impairment and the expected future taxable income available to realize deferred tax assets, also in part, rely on estimates of quantities of net reserves. Refer to the applicable sections below for further discussion of these accounting estimates.

The estimation of quantities of net reserves is a highly technical process performed by our petroleum engineers and geoscientists for crude oil and condensate, NGLs and natural gas, which is based upon several underlying assumptions. The reserve estimates may change as additional information becomes available and as contractual, operational, economic and political conditions change. We evaluate our reserves using drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. Technologies used in proved reserves estimation includes statistical analysis of production performance, decline curve analysis, pressure and rate transient analysis, pressure gradient analysis, reservoir simulation and volumetric analysis. The observed statistical nature of production performance coupled with highly certain reservoir continuity or quality within the reliable technology areas and sufficient proved developed locations establish the reasonable certainty criteria required for booking proved reserves. The data for a given reservoir may also change over time as a result of numerous factors including, but not limited to, additional development activity and future development costs, production history and continual reassessment of the viability of future production volumes under varying economic conditions.

Reserve estimates are based on an unweighted arithmetic average of commodity prices during the 12-month period, using the closing prices on the first day of each month, as defined by the SEC. The table below provides the 2019 SEC pricing for certain benchmark prices:

	2019 SEC Pricing
WTI Crude oil *(per bbl)*	$ 55.69
Henry Hub natural gas *(per mmbtu)*	$ 2.58
Brent crude oil *(per bbl)*	$ 63.15
Mont Belvieu NGLs *(per bbl)*	$ 18.41

When determining the December 31, 2019 proved reserves for each property, the benchmark prices listed above were adjusted using price differentials that account for property-specific quality and location differences.

If crude oil prices in the future average below prices used to determine proved reserves at December 31, 2019, it could have an adverse effect on our estimates of proved reserve volumes and the value of our business. Future reserve revisions could also result from changes in capital funding, drilling plans and governmental regulation, among other things. It is difficult to estimate the magnitude of any potential price change and the effect on proved reserves, due to numerous factors (including future crude oil price and performance revisions). For further discussion of risks associated with our estimation of proved reserves, see Part I. **Item 1A. Risk Factors**.

Depreciation and depletion of crude oil and condensate, NGLs and natural gas producing properties is determined by the units-of-production method and could change with revisions to estimated proved reserves. While revisions of previous reserve estimates have not historically been significant to the depreciation and depletion rates of our segments, any reduction in proved reserves, could result in an acceleration of future DD&A expense. The following table illustrates, on average, the sensitivity of each segment's units-of-production DD&A per boe and pretax income to a hypothetical 10% change in 2019 proved reserves based on 2019 production.

	Impact of a 10% Increase in Proved Reserves		Impact of a 10% Decrease in Proved Reserves	
(In millions, except per boe)	DD&A per boe	Pretax Income	DD&A per boe	Pretax Income
United States	$ (1.73)	$ 205	$ 2.12	$ (250)
International	$ (0.33)	$ 11	$ 0.40	$ (13)

Fair Value Estimates

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 at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value, or range of present values, using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.
- Level 3 – Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. See Item 8. Financial Statements and Supplementary Data – **Note 16** to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurements include:

- assets and liabilities acquired in a business combination;
- assets acquired in an asset acquisition;
- impairment assessments of long-lived assets;
- impairment assessments of goodwill;
- recorded value of derivative instruments; and
- recorded value of pension plan assets.

The need to test long-lived assets and goodwill for impairment can be based on several indicators, including a significant reduction in prices of crude oil and condensate, NGLs and natural gas, sustained declines in our common stock, reductions to our Capital Budget, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which the property is located.

Impairment Assessments of Long-Lived Assets

Long-lived assets in use are assessed for impairment whenever changes in facts and circumstances indicate that the carrying value of the assets may not be recoverable. For purposes of an impairment evaluation, long-lived assets must be grouped at the lowest level for which independent cash flows can be identified, which generally is field-by-field or, in certain instances, by logical grouping of assets if there is significant shared infrastructure or contractual terms that cause economic interdependency amongst separate, discrete fields. If the sum of the undiscounted estimated cash flows from the use of the asset group and its eventual disposition is less than the carrying value of an asset group, the carrying value is written down to the estimated fair value. During 2019, proved property impairments were primarily as a result of anticipated sales for certain non-core proved properties in our United States segment and the sale of our non-operated interest in the Atrush block (Kurdistan) in our International segment. We estimated the fair values using a market approach, based upon anticipated sales proceeds less costs to sell, and recognized impairments.

Fair value calculated for the purpose of testing our long-lived assets for impairment is estimated using the present value of expected future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- *Future crude oil and condensate, NGLs and natural gas prices.* Our estimates of future prices are based on our analysis of market supply and demand and consideration of market price indicators. Although these commodity prices may experience extreme volatility in any given year, we believe long-term industry prices are driven by global market supply and demand. To estimate supply, we consider numerous factors, including the worldwide resource base, depletion rates and OPEC production policies. We believe demand is largely driven by global economic factors, such as population and income growth, governmental policies and vehicle stocks. The prices we use in our fair value estimates are consistent with those used in our planning and capital investment reviews. There has been significant volatility in crude oil and condensate, NGLs and natural gas prices and estimates of such future prices are inherently imprecise. See Item 1A. Risk Factors for further discussion on commodity prices.
- *Estimated quantities of crude oil and condensate, NGLs and natural gas.* Such quantities are based on a combination of proved reserves and risk-weighted probable reserves and resources such that the combined volumes represent the most likely expectation of recovery. See Item 1A. Risk Factors for further discussion on reserves.
- *Expected timing of production.* Production forecasts are the outcome of engineering studies which estimate reserves, as well as expected capital programs. The actual timing of the production could be different than the projection. Cash flows realized later in the projection period are less valuable than those realized earlier due to the time value of money. The expected timing of production that we use in our fair value estimates is consistent with that used in our planning and capital investment reviews.
- *Discount rate commensurate with the risks involved.* We apply a discount rate to our expected cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. A higher discount rate decreases the net present value of cash flows.
- *Future capital requirements.* Our estimates of future capital requirements are based upon a combination of authorized spending and internal forecasts.

We base our fair value estimates on projected financial information which we believe to be reasonably likely to occur. An estimate of the sensitivity to changes in assumptions in our undiscounted cash flow calculations is not practicable, given the numerous assumptions (e.g. reserves, pace and timing of development plans, commodity prices, capital expenditures, operating costs, drilling and development costs, inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future undiscounted cash flows would likely be partially offset by lower costs. As of December 31, 2019 our estimated undiscounted cash flows relating to our remaining long-lived assets significantly exceeded their carrying values. See Item 8. Financial Statements and Supplementary Data **Note 11** and **Note 16** to the consolidated financial statements for discussion of impairments recorded in 2019, 2018 and 2017 and the related fair value measurements.

Impairment Assessments of Goodwill

Goodwill is tested for impairment on an annual basis, or between annual tests when events or changes in circumstances indicate the fair value may have been reduced below its carrying value. Goodwill is tested for impairment at the reporting unit level. Our reporting units are the same as our reporting segments, of which only International includes goodwill. As of December 31, 2019, our consolidated balance sheet included goodwill of $95 million. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Our policy is to first assess the qualitative factors in order to determine whether the fair value of our International reporting unit is more likely than not less than its carrying amount. Certain qualitative factors used in our evaluation include, among other things, the results of the most recent quantitative assessment of the goodwill impairment test; macroeconomic conditions; industry and market conditions (including commodity prices and cost factors); overall financial performance; and other relevant entity-specific events. If, after considering these events and circumstances we determined that it is more likely than not that the fair value of the International reporting unit is less than its carrying amount, a quantitative goodwill test is performed. The quantitative goodwill test is performed using a combination of market and income approaches. The market approach references observable inputs specific to us and our industry, such as the price of our common equity, our enterprise value, and valuation multiples of us and our peers from the investor analyst community. The income approach utilizes discounted cash flows, which are based on forecasted assumptions. Key assumptions to the income approach are the same as those described above regarding our impairment assessment of long lived assets and are consistent with those that management uses to make business decisions.

During the second quarter of 2019, we performed our annual impairment test of goodwill using the qualitative assessment. Our qualitative assessment considered the significant excess fair value over carrying value in our most recent step 1 test (second quarter of 2017) and noted a general improvement in the qualitative factors above. After assessing the totality of the qualitative factors which could have a positive or negative impact on goodwill, our assessment did not indicate that it is more likely than not that the fair value is less than its carrying value. As a result, we concluded that no impairment to goodwill was required for our International reporting unit. We believe the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in such assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. See Item 8. Financial Statements and Supplementary Data **Note 14** to the consolidated financial statements for additional discussion of goodwill.

Derivatives

We record all derivative instruments at fair value. Fair value measurements for all our derivative instruments are based on observable market-based inputs that are corroborated by market data and are discussed in Item 8. Financial Statements and Supplementary Data – **Note 15** to the consolidated financial statements. Additional information about derivatives and their valuation may be found in **Item 7A. Quantitative and Qualitative Disclosures About Market Risk**.

Pension Plan Assets

Pension plan assets are measured at fair value. See Item 8. Financial Statements and Supplementary Data – **Note 19** to the consolidated financial statements for discussion of the fair value of plan assets and the presentation of the fair value of our defined benefit pension plan's assets by level within the fair value hierarchy as of December 31, 2019 and 2018.

Income Taxes

We are subject to income taxes in numerous taxing jurisdictions worldwide. Estimates of income taxes to be recorded involve interpretation of complex tax laws and assessment of the effects of foreign taxes on our U.S. federal income taxes.

Uncertainty exists regarding tax positions taken in previously filed tax returns which remain subject to examination, along with positions expected to be taken in future returns. We provide for unrecognized tax benefits, based on the technical merits, when it is more likely than not that an uncertain tax position will not be sustained upon examination. Adjustments are made to the uncertain tax positions when facts and circumstances change, such as the closing of a tax audit; court proceedings; changes in applicable tax laws, including tax case rulings and legislative guidance; or expiration of the applicable statute of limitations.

We have recorded deferred tax assets and liabilities, measured at enacted tax rates, for temporary differences between book basis and tax basis, tax credit carryforwards and operating loss carryforwards. In accordance with U.S. GAAP accounting standards, we routinely assess the realizability of our deferred tax assets and reduce such assets, to the expected realizable amount, by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. In assessing the need for additional or adjustments to existing valuation allowances, we consider all available positive and negative evidence. Positive evidence includes reversals of temporary differences, forecasts of future taxable income, assessment of future business assumptions and applicable tax planning strategies that are prudent and feasible. Negative evidence includes losses in recent years as well as the forecasts of future income (loss) in the realizable period. In making our assessment regarding valuation allowances, we weight the evidence based on objectivity.

We base our future taxable income estimates on projected financial information which we believe to be reasonably likely to occur. Numerous judgments and assumptions are inherent in the estimation of future taxable income, including factors such as future operating conditions and the assessment of the effects of foreign taxes on our U.S. federal income taxes. Future operating conditions can be affected by numerous factors, including (i) future crude oil and condensate, NGLs and natural gas prices, (ii) estimated quantities of crude oil and condensate, NGLs and natural gas, (iii) expected timing of production, and (iv) future capital requirements. These assumptions are described in further detail above regarding our impairment assessment of long-lived assets. An estimate of the sensitivity to changes in assumptions resulting in future taxable income calculations is not practicable, given the numerous assumptions that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced commodity prices on future taxable income would likely be partially offset by lower capital expenditures.

Based on the assumptions and judgments described above, as of December 31, 2019, we reflect a valuation allowance in our consolidated balance sheet of $699 million against our gross deferred tax assets of $2.4 billion in various jurisdictions in which we operate. Our gross deferred tax assets consist primarily of federal U.S. operating loss carryforwards of $655 million, which will expire in 2035 - 2037, and $829 million which can be carried forward indefinitely. Since December 31, 2016, we have maintained a full valuation allowance on our net federal deferred tax assets. If objective negative evidence in the form of cumulative losses are no longer present and additional weight is given to subjective evidence such as forecasted projections of taxable income in future years, we would adjust the amount of the federal deferred tax assets considered realizable and reduce the provision for income taxes in the period of adjustment. See Item 8. Financial Statements and Supplementary Data – **Note 8** to the consolidated financial statements for further detail.

Pension and Other Postretirement Benefit Obligations

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the following:

- the discount rate for measuring the present value of future plan obligations;
- the expected long-term return on plan assets;
- the rate of future increases in compensation levels; and

We develop our demographics and utilize the work of third-party actuaries to assist in the measurement of these obligations. We have selected different discount rates for our U.S. pension plans and our other U.S. postretirement benefit plans due to the different projected benefit payment patterns. In determining the assumed discount rates, our methods include a review of market yields on high-quality corporate debt and use of our third-party actuary's discount rate model. This model calculates an equivalent single discount rate for the projected benefit plan cash flows using a yield curve derived from bond yields. The yield curve represents a series of annualized individual spot discount rates from 0.5 to 99 years. The bonds used are rated AA or higher by a recognized rating agency, only non-callable bonds are included and outlier bonds (bonds that have a yield to maturity that significantly deviates from the average yield within each maturity grouping) are removed. Each issue is required to have at least $300 million par value outstanding. The constructed yield curve is based on those bonds representing the 50% highest yielding issuances within each defined maturity group.

The asset rate of return assumption for the funded U.S. plan considers the plan's asset mix (currently targeted at approximately 55% equity and 45% other fixed income securities), past performance and other factors. Certain components of the asset mix are modeled with various assumptions regarding inflation, debt returns and stock yields.

Compensation change assumptions are based on historical experience, anticipated future management actions and demographics of the benefit plans. Health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends.

Item 8. Financial Statements and Supplementary Data – **Note 19** to the consolidated financial statements includes detailed information about the assumptions used to calculate the components of our annual defined benefit pension and other postretirement plan expense, as well as the obligations and accumulated other comprehensive income reported on the consolidated balance sheets.

Contingent Liabilities

We accrue contingent liabilities for environmental remediation, tax deficiencies related to operating taxes, as well as tax disputes and litigation claims when such contingencies are probable and estimable. Actual costs can differ from estimates for many reasons. For instance, settlement costs for claims and litigation can vary from estimates based on differing interpretations of laws, opinions on responsibility and assessments of the amount of damages. Similarly, liabilities for environmental remediation may vary from estimates because of changes in laws, regulations and their interpretation, additional information on the extent and nature of site contamination and improvements in technology. Our in-house legal counsel regularly assesses these contingent liabilities. In certain circumstances outside legal counsel is utilized.

We generally record losses related to these types of contingencies as other operating expense or general and administrative expense in the consolidated statements of income, except for tax contingencies unrelated to income taxes, which are recorded as taxes other than income. For additional information on contingent liabilities, see **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Management's Discussion and Analysis of Environmental Matters, Litigation and Contingencies**.

An estimate of the sensitivity to net income if other assumptions had been used in recording these liabilities is not practical because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, in terms of both the probability of loss and the estimates of such loss.

Accounting Standards Not Yet Adopted

See Item 8. Financial Statements and Supplementary Data – **Note 2** to the consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks related to the volatility of crude oil and condensate, NGLs, and natural gas prices as the volatility of these prices continues to impact our industry. We expect commodity prices to remain volatile and unpredictable in the future. We are also exposed to market risks related to changes in interest rates. We employ various strategies, including the use of financial derivative instruments, to manage the risks related to these fluctuations. We are at risk for changes in the fair value of all of our derivative instruments; however, such risk should be mitigated by price or rate changes related to the underlying commodity or financial transaction. While the use of derivative instruments could materially affect our results of operations in particular quarterly or annual periods, we believe that the use of these instruments will not have a material adverse effect on our financial position or liquidity.

See Item 8. Financial Statements and Supplementary Data – **Note 15** and **Note 16** to the consolidated financial statements for more information about the fair value measurement of our derivatives, the amounts recorded in our consolidated balance sheets and statements of income and the related notional amounts.

Commodity Price Risk

Our strategy is to obtain competitive prices for our products and allow operating results to reflect market price movements dictated by supply and demand. However, management will periodically protect prices on forecasted sales to support cash flow and liquidity, as deemed appropriate. We may use a variety of commodity derivative instruments, including futures, forwards, swaps and combinations of options, as part of an overall program to manage commodity price risk in our business. Our consolidated results for 2019, 2018 and 2017 were impacted by crude oil and natural gas derivatives related to a portion of our forecasted United States sales.

As of December 31, 2019, we had various open commodity derivatives related to crude oil and natural gas with a net asset position of $4 million. Based on the December 31, 2019, published NYMEX WTI and Henry Hub futures prices, a hypothetical 10% increase or decrease (per bbl for crude oil and per MMBtu for natural gas) would change the fair values of our net commodity derivative open positions to the following:

(In millions)	**Hypothetical Price Increase of 10%**	**Hypothetical Price Decrease of 10%**
Crude oil derivatives	$ (65)	$ 50
Natural gas derivatives	(1)	—
Total	$ (66)	$ 50

Interest Rate Risk

At December 31, 2019, our portfolio of long-term debt is comprised of fixed-rate instruments with an outstanding balance of $5.5 billion. Our sensitivity to interest rate movements and corresponding changes in the fair value of our fixed-rate debt portfolio affects our results of operations and cash flows only when we elect to repurchase or otherwise retire fixed-rate debt at prices different than carrying value.

We also manage our exposure to interest rate movements by utilizing interest rate swap agreements to hedge variations in cash flows related to the 1-month LIBOR component of future lease payments on our future Houston office. At December 31, 2019, we had forward starting interest rate swap agreements with a total notional of $320 million designated as cash flow hedges. The incremental change on the fair value of a hypothetical 10% increase in interest rates by $3 million, resulting in a fair value of $5 million. The incremental change on the fair value of a hypothetical 10% decrease in interest rates on these interest rate swaps by $2 million, resulting in a fair value of less than $1 million.

Counterparty Risk

We are also exposed to financial risk in the event of nonperformance by counterparties. If commodity prices fall below current levels, some of our counterparties may experience liquidity problems and may not be able to meet their financial obligations to us. We review the creditworthiness of counterparties and use master netting agreements when appropriate.

Item 8. Financial Statements and Supplementary Data

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Management's Responsibilities for Financial Statements

To the Stockholders of Marathon Oil Corporation:

The accompanying consolidated financial statements of Marathon Oil Corporation and its consolidated subsidiaries ("Marathon Oil") are the responsibility of management and have been prepared in conformity with accounting principles generally accepted in the United States. They necessarily include some amounts that are based on best judgments and estimates. The financial information displayed in other sections of this Annual Report on Form 10-K is consistent with these consolidated financial statements.

Marathon Oil seeks to assure the objectivity and integrity of its financial records by careful selection of its managers, by organization arrangements that provide an appropriate division of responsibility and by communications programs aimed at assuring that its policies and methods are understood throughout the organization.

The Board of Directors pursues its oversight role in the area of financial reporting and internal control over financial reporting through its Audit and Finance Committee. This Committee, composed solely of independent directors, regularly meets (jointly and separately) with the independent registered public accounting firm, management and internal auditors to monitor the proper discharge by each of their responsibilities relative to internal accounting controls and the consolidated financial statements.

/s/ Lee M. Tillman	/s/ Dane E. Whitehead
Chairman, President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*

Management's Report on Internal Control over Financial Reporting

To the Stockholders of Marathon Oil Corporation:

Marathon Oil's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13(a) – 15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. 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.

An evaluation of the design and effectiveness of our internal control over financial reporting, based on the 2013 framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer. Based on the results of this evaluation, Marathon Oil's management concluded that its internal control over financial reporting was effective as of December 31, 2019.

The effectiveness of Marathon Oil's internal control over financial reporting as of December 31, 2019 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Lee M. Tillman	/s/ Dane E. Whitehead
Chairman, President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Marathon Oil Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheet of Marathon Oil Corporation and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income, of stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company'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 Company's consolidated financial statements and on the Company'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 Company 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 Condensate, Natural Gas Liquids (NGLs) and Natural Gas Reserves on Proved Oil and Gas Properties, Net

As described in Notes 1 and 10 to the consolidated financial statements, the Company's consolidated property, plant and equipment, net balance was $17,000 million as of December 31, 2019, and depreciation, depletion, and amortization (DD&A) expense for the year ended December 31, 2019 was $2,397 million, both of which substantially relate to proved oil and gas properties. The Company uses the successful efforts method of accounting for its oil and gas producing activities. Under this method, capitalized costs to acquire oil and natural gas properties are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. As discussed by management, reserve estimates may change as a result of a number of factors, including but not limited to, changes in contractual, operational, economic and political conditions; additional development activity and future development costs; production history; and continual reassessment of the viability of future production volumes under varying economic conditions. The estimates of oil and gas reserves have been developed by specialists, specifically petroleum engineers and geoscientists.

The principal considerations for our determination that performing procedures relating to the impact of proved oil and condensate, NGLs and natural gas reserves on proved oil and gas properties, net is a critical audit matter are there was significant judgment by management, including the use of specialists, when developing the estimates of proved oil and gas reserves, which in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures to evaluate the significant assumptions used in developing those estimates, including future development costs and future production volumes.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and condensate, NGLs and natural gas reserves and the calculation of DD&A expense. These procedures also included, among others, evaluating the significant assumptions used by management in developing these estimates, including future development costs and future production volumes, and testing the unit-of-production rate used to calculate DD&A expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of these estimates. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialist. The procedures performed also included tests of the data used by the specialists and an evaluation of the specialists' findings. Evaluating the significant assumptions relating to the estimates of proved oil and condensate, NGLs and natural gas reserves also involved obtaining evidence to support the reasonableness of the assumptions, including whether the assumptions used were reasonable considering the current and past performance of the Company, and whether they were consistent with evidence obtained in other areas of the audit.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 20, 2020

We have served as the Company's auditor since 1982.

MARATHON OIL CORPORATION
Consolidated Statements of Income

(In millions, except per share data)	Year Ended December 31, 2019	2018	2017
Revenues and other income:			
Revenues from contracts with customers	$ 5,063	$ 5,902	$ 4,247
Net loss on commodity derivatives	(72)	(14)	(36)
Marketing revenues	—	—	162
Income from equity method investments	87	225	256
Net gain on disposal of assets	50	319	58
Other income	62	150	78
Total revenues and other income	5,190	6,582	4,765
Costs and expenses:			
Production	712	842	716
Marketing, including purchases from related parties	—	—	168
Shipping, handling and other operating	605	575	431
Exploration	149	289	409
Depreciation, depletion and amortization	2,397	2,441	2,372
Impairments	24	75	229
Taxes other than income	311	299	183
General and administrative	356	394	371
Total costs and expenses	4,554	4,915	4,879
Income (loss) from operations	636	1,667	(114)
Net interest and other	(244)	(226)	(270)
Other net periodic benefit costs	3	(14)	(19)
Loss on early extinguishment of debt	(3)	—	(51)
Income (loss) from continuing operations before income taxes	392	1,427	(454)
Provision (benefit) for income taxes	(88)	331	376
Income (loss) from continuing operations	480	1,096	(830)
Loss from discontinued operations	—	—	(4,893)
Net income (loss)	$ 480	$ 1,096	$ (5,723)
Per basic share:			
Income (loss) from continuing operations	$ 0.59	$ 1.30	$ (0.97)
Loss from discontinued operations	$ —	$ —	$ (5.76)
Net income (loss)	$ 0.59	$ 1.30	$ (6.73)
Per diluted share:			
Income (loss) from continuing operations	$ 0.59	$ 1.29	$ (0.97)
Loss from discontinued operations	$ —	$ —	$ (5.76)
Net income (loss)	$ 0.59	$ 1.29	$ (6.73)
Weighted average common shares outstanding:			
Basic	810	846	850
Diluted	810	847	850

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Statements of Comprehensive Income

(In millions)	Year Ended December 31, 2019	2018	2017
Net income (loss)	$ 480	$ 1,096	$ (5,723)
Other comprehensive income (loss), net of tax			
Postretirement and postemployment plans:			
Change in actuarial gain and other	54	117	21
Income taxes on postretirement and postemployment plans	(38)	4	7
Postretirement and postemployment plans, net of tax	16	121	28
Derivative hedges:			
Net unrecognized gain (loss)	2	—	(13)
Reclassification of gains on terminated derivative hedges	—	—	(47)
Income taxes on derivative hedges	—	—	21
Derivative hedges, net of tax	2	—	(39)
Foreign currency translation:			
Net recognized loss reclassified to discontinued operations	—	—	34
Foreign currency translation adjustment related to sale of U.K. business	30	—	—
Income taxes on foreign currency translation	(7)	—	(4)
Foreign currency translation, net of tax	23	—	30
Other, net of tax	1	4	2
Other comprehensive income	42	125	21
Comprehensive income (loss)	$ 522	$ 1,221	$ (5,702)

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Balance Sheet

(In millions, except par values and share amounts)	December 31, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$ 858	$ 1,462
Receivables, less reserve of $11 and $11	1,122	1,079
Inventories	72	96
Other current assets	83	257
Current assets held for sale	—	27
Total current assets	2,135	2,921
Equity method investments	663	745
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $18,003 and $21,830	17,000	16,804
Goodwill	95	97
Other noncurrent assets	352	723
Noncurrent assets held for sale	—	31
Total assets	$ 20,245	$ 21,321
Liabilities		
Current liabilities:		
Accounts payable	$ 1,307	$ 1,320
Payroll and benefits payable	112	154
Accrued taxes	118	181
Other current liabilities	208	170
Current liabilities held for sale	—	7
Total current liabilities	1,745	1,832
Long-term debt	5,501	5,499
Deferred tax liabilities	186	199
Defined benefit postretirement plan obligations	183	195
Asset retirement obligations	243	1,081
Deferred credits and other liabilities	234	279
Noncurrent liabilities held for sale	—	108
Total liabilities	8,092	9,193
Commitments and contingencies		
Stockholders' Equity		
Preferred stock – no shares issued or outstanding (no par value, 26 million shares authorized)	—	—
Common stock:		
Issued – 937 million shares (par value $1 per share, 1.925 billion shares authorized at December 31, 2019 and December 31, 2018)	937	937
Held in treasury, at cost – 141 million shares and 118 million shares	(4,089)	(3,816)
Additional paid-in capital	7,207	7,238
Retained earnings	7,993	7,706
Accumulated other comprehensive income	105	63
Total stockholders' equity	12,153	12,128
Total liabilities and stockholders' equity	$ 20,245	$ 21,321

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

(In millions)	Year Ended December 31, 2019	2018	2017
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income (loss)	$ 480	$ 1,096	$ (5,723)
Adjustments to reconcile net income (loss) to net cash provided by operating activities from continuing operations:			
Discontinued operations	—	—	4,893
Depreciation, depletion and amortization	2,397	2,441	2,372
Impairments	24	75	229
Exploratory dry well costs and unproved property impairments	114	255	323
Net gain on disposal of assets	(50)	(319)	(58)
Loss on early extinguishment of debt	3	—	51
Deferred income taxes	(34)	52	(61)
Net loss on derivative instruments	72	14	36
Net settlements of derivative instruments	52	(281)	45
Pension and other post retirement benefits, net	(52)	(65)	(46)
Stock-based compensation	60	53	49
Equity method investments, net	18	45	20
Changes in:			
Current receivables	52	(133)	(334)
Inventories	3	(1)	10
Current accounts payable and accrued liabilities	(187)	179	297
Other current assets and liabilities	(4)	(22)	1
All other operating, net	(199)	(155)	(116)
Net cash provided by operating activities from continuing operations	2,749	3,234	1,988
Investing activities:			
Additions to property, plant and equipment	(2,550)	(2,753)	(1,974)
Additions to other assets	36	(26)	(25)
Acquisitions, net of cash acquired	(293)	(25)	(1,891)
Disposal of assets, net of cash transferred to the buyer	(76)	1,264	1,787
Equity method investments - return of capital	64	57	64
All other investing, net	1	13	(5)
Net cash used in investing activities from continuing operations	(2,818)	(1,470)	(2,044)
Financing activities:			
Borrowings	600	—	988
Debt repayments	(600)	—	(2,764)
Debt extinguishment costs	(2)	—	(46)
Purchases of common stock	(362)	(713)	(11)
Dividends paid	(162)	(169)	(170)
All other financing, net	(9)	23	—
Net cash used in financing activities	(535)	(859)	(2,003)
Net increase in cash and cash equivalents of discontinued operations (Note 5)	—	—	130
Effect of exchange rate on cash and cash equivalents	—	(2)	4
Net increase (decrease) in cash and cash equivalents	(604)	903	(1,925)
Cash and cash equivalents at beginning of period	1,462	563	2,488
Cash and cash equivalents included in current assets held for sale	—	(4)	—
Cash and cash equivalents at end of period	$ 858	$ 1,462	$ 563

The accompanying notes are an integral part of these consolidated financial statements.

MARATHON OIL CORPORATION
Consolidated Statements of Stockholders' Equity

(In millions)	Total Equity of Marathon Oil Stockholders: Preferred Stock	Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
December 31, 2016 Balance	$ —	$ 937	$ (3,431)	$ 7,446	$ 12,672	$ (83)	$ 17,541
Shares issued - stock-based compensation	—	—	117	(50)	—	—	67
Shares repurchased	—	—	(11)	—	—	—	(11)
Stock-based compensation	—	—	—	(17)	—	—	(17)
Net loss	—	—	—	—	(5,723)	—	(5,723)
Other comprehensive income	—	—	—	—	—	21	21
Dividends paid ($0.20 per share)	—	—	—	—	(170)	—	(170)
December 31, 2017 Balance	$ —	$ 937	$ (3,325)	$ 7,379	$ 6,779	$ (62)	$ 11,708
Shares issued - stock-based compensation	—	—	221	(109)	—	—	112
Shares repurchased	—	—	(712)	—	—	—	(712)
Stock-based compensation	—	—	—	(32)	—	—	(32)
Net income	—	—	—	—	1,096	—	1,096
Other comprehensive income	—	—	—	—	—	125	125
Dividends paid ($0.20 per share)	—	—	—	—	(169)	—	(169)
December 31, 2018 Balance	$ —	$ 937	$ (3,816)	$ 7,238	$ 7,706	$ 63	$ 12,128
Cumulative-effect adjustment (Note 2)	—	—	—	—	(31)	—	(31)
Shares issued - stock-based compensation	—	—	89	(26)	—	—	63
Shares repurchased	—	—	(362)	—	—	—	(362)
Stock-based compensation	—	—	—	(5)	—	—	(5)
Net income	—	—	—	—	480	—	480
Other comprehensive income	—	—	—	—	—	42	42
Dividends paid ($0.20 per share)	—	—	—	—	(162)	—	(162)
December 31, 2019 Balance	$ —	$ 937	$ (4,089)	$ 7,207	$ 7,993	$ 105	$ 12,153

(Shares in millions)	Preferred Stock	Common Stock	Treasury Stock
December 31, 2016 Balance	—	937	90
Shares issued - stock-based compensation	—	—	(3)
December 31, 2017 Balance	—	937	87
Shares issued - stock-based compensation	—	—	(6)
Shares repurchased	—	—	37
December 31, 2018 Balance	—	937	118
Shares issued - stock-based compensation	—	—	(2)
Shares repurchased	—	—	25
December 31, 2019 Balance	—	937	141

The accompanying notes are an integral part of these consolidated financial statements.

1. Summary of Principal Accounting Policies

We are an independent exploration and production company engaged in exploration, production and marketing of crude oil and condensate, NGLs and natural gas; as well as production and marketing of products manufactured from natural gas, such as LNG and methanol, in E.G.

Basis of presentation and principles applied in consolidation – These consolidated financial statements, including notes have been prepared in accordance with U.S. GAAP. These consolidated financial statements include the accounts of our controlled subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis.

Equity method investments – Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. This includes entities in which we hold majority ownership but the minority stockholders have substantive participating rights in the investee. Income from equity method investments represents our proportionate share of net income generated by the equity method investees and is reflected in revenues and other income in our consolidated statements of income. Equity method investments are included as noncurrent assets on the consolidated balance sheet.

Equity method investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value may have occurred. When a loss is deemed to have occurred and is other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in income.

Discontinued operations – As a result of the sale of our Canadian business in 2017, we reflected this business as discontinued operations in all historical periods presented. Disclosures in this report related to results of operations and cash flows are presented on the basis of continuing operations unless otherwise stated. See **Note 5** for discussion of the divestiture in further detail.

Use of estimates – The preparation of financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods.

Estimated quantities of crude oil and condensate, NGLs and natural gas reserves is a significant estimate that requires judgment. All of the reserve data included in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and condensate, NGLs and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and condensate, NGLs and natural gas reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and condensate, NGLs and natural gas that are ultimately recovered. See unaudited Supplementary Data - **Supplementary Information on Oil and Gas Producing Activities** for further detail.

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment, asset retirement obligations, goodwill, valuation of derivative instruments and valuation allowances for deferred income tax assets, among others. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Foreign currency transactions – The U.S. dollar is the functional currency of our foreign operating subsidiaries. Foreign currency transaction gains and losses are included in net income.

Revenue recognition – Revenues associated with the sales of crude oil and condensate, NGLs and natural gas are recognized when our performance obligation is satisfied, which typically occurs at the point where control transfers to the customer based on contract terms. Revenue is measured as the amount the company expects to receive in exchange for transferring commodities to the customer. Our hydrocarbon sales are typically based on prevailing market-based prices and may include quality or location differential adjustments. Payment is generally due within 30 days of delivery.

We typically incur shipping and handling costs prior to control transferring to the customer and account for these activities as fulfillment costs. These costs are reflected in shipping, handling and other operating expense line in our consolidated statement of income.

Our U.S. production of crude oil and condensate, NGLs and natural gas is generally sold immediately and transported to market. In our international segment, liquid hydrocarbon production may be stored as inventory and sold at a later time.

Cash and cash equivalents – Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with original maturities of three months or less.

Accounts receivable – The majority of our receivables are from purchasers of commodities or joint interest owners in properties we operate, both of which are recorded at estimated or invoiced amounts and do not bear interest. We often have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We conduct credit reviews of commodity purchasers prior to making commodity sales to new customers or increasing credit for existing customers. Based on these reviews, we may require a standby letter of credit or a financial guarantee. We routinely assess the collectability of receivable balances to determine if the amount of the reserve in allowance for doubtful accounts is sufficient.

Inventories – Crude oil and natural gas are recorded at weighted average cost and carried at the lower of cost or net realizable value. Supplies and other items consist principally of tubular goods and equipment which are valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate.

We may enter into a contract to sell a particular quantity and quality of crude oil at a specified location and date to a particular counterparty, and simultaneously agree to buy a particular quantity and quality of the same commodity at a specified location on the same or another specified date from the same counterparty. We account for such matching buy/sell arrangements as exchanges of inventory.

Derivative instruments – We may use derivatives to manage a portion of our exposure to commodity price risk, commodity locational risk and interest rate risk. All derivative instruments are recorded at fair value. Commodity derivatives and interest rate swaps are reflected on our consolidated balance sheet on a net basis by counterparty, as they are governed by master netting agreements. Cash flows related to derivatives used to manage commodity price risk, and interest rate risk are classified in operating activities. Our derivative instruments contain no significant contingent credit features.

Fair value hedges – We may use interest rate swaps to manage our exposure to interest rate risk associated with fixed interest rate debt in our portfolio. Changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in net income the extent to which the hedge is not effective in achieving offsetting changes in fair value.

Cash flow hedges – We may use interest rate derivative instruments to manage the risk of interest rate changes during the period prior to anticipated borrowings as well as to stabilize future lease payments on our future Houston office, and designate them as cash flow hedges. Derivative instruments designated as cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until the hedged transaction affects earnings and are then reclassified into net income. Beginning in 2019, ineffective portions of a cash flow hedge are no longer measured or disclosed separately. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable or the cash flow hedge is no longer expected to be highly effective, subsequent changes in fair value of the derivatives instrument are recorded in net income.

Derivatives not designated as hedges – Derivatives that are not designated as hedges may include commodity derivatives used primarily to manage price and locational risks on the forecasted sale of crude oil, NGLs, and natural gas that we produce. Changes in the fair value of derivatives not designated as hedges are recognized immediately in net income.

Concentrations of credit risk – All of our financial instruments, including derivatives, involve elements of credit and market risk. The most significant portion of our credit risk relates to nonperformance by counterparties. The counterparties to our financial instruments consist primarily of major financial institutions and companies within the energy industry. To manage counterparty risk associated with financial instruments, we select and monitor counterparties based on our assessment of their financial strength and on credit ratings, if available. Additionally, we limit the level of exposure with any single counterparty.

Fair value transfer – We recognize transfers between levels of the fair value hierarchy as of the end of the reporting period.

Property, plant and equipment – We use the successful efforts method of accounting for oil and gas producing activities.

Property acquisition costs – Costs to acquire mineral interests in oil and natural gas properties, to drill exploratory wells in progress and those that find proved reserves, and to drill development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves but cannot yet be classified as proved are capitalized if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended exploratory well costs is monitored continuously and reviewed at least quarterly.

Depreciation, depletion and amortization – Capitalized costs to acquire oil and natural gas properties are depreciated and depleted on a units-of-production basis based on estimated proved reserves. Capitalized costs of exploratory wells and development costs are depreciated and depleted on a units-of-production basis based on estimated proved developed reserves. Support equipment and other property, plant and equipment related to oil and gas producing activities, as well as property, plant and equipment unrelated to oil and gas producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets as summarized below.

Type of Asset	Range of Useful Lives
Office furniture, equipment and computer hardware	4 to 15 years
Pipelines	5 to 40 years
Plants, facilities and infrastructure	3 to 40 years

Impairments – We evaluate our oil and gas producing properties, including capitalized costs of exploratory wells and development costs, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure or contractual terms that cause economic interdependency amongst separate, discrete fields. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is also considered. When unproved property investments are deemed to be impaired, this amount is reported in exploration expenses in our consolidated statements of income.

Dispositions – When property, plant and equipment depreciated on an individual basis is sold or otherwise disposed of, any gains or losses are reflected in net gain (loss) on disposal of assets in our consolidated statements of income. Gains on the disposal of property, plant and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized either when the assets are classified as held for sale, or are measured using a probability weighted income approach based on both the anticipated sales price and a held-for-use model depending on timing of the sale. Proceeds from the disposal of property, plant and equipment depreciated on a group basis are credited to accumulated depreciation, depletion and amortization with no immediate effect on net income until net book value is reduced to zero.

Goodwill – Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Such goodwill is not amortized, but rather is tested for impairment annually and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to a reporting unit. The fair value of a reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the recorded goodwill is impaired to its implied fair value with a charge to impairments.

Environmental costs – We provide for remediation costs and penalties when the responsibility to remediate is probable and the amount of associated costs can be reasonably estimated. The timing of remediation accruals coincides with completion of a feasibility study or the commitment to a formal plan of action. Remediation liabilities are accrued based on estimates of known environmental exposure and are discounted when the estimated amounts are reasonably fixed or reliably determinable. Environmental expenditures are capitalized only if the costs mitigate or prevent future contamination or if the costs improve the environmental safety or efficiency of the existing assets.

Asset retirement obligations – The fair value of asset retirement obligations is recognized in the period in which the obligations are incurred if a reasonable estimate of fair value can be made. Our asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities. Asset retirement obligations for such facilities include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures and restoration costs of land, including those leased. Estimates of these costs are developed for each property based on the type of production facilities and equipment, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering professionals.

Inflation rates and credit-adjusted-risk-free interest rates are used to estimate the fair value of asset retirement obligations. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis based on estimated proved developed reserves for oil and gas production facilities, while accretion of the liability occurs over the useful lives of the assets.

Deferred income taxes – Deferred tax assets and liabilities, measured at enacted tax rates, are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. We routinely assess the realizability of our deferred tax assets based on several interrelated factors and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. These factors include whether we are in a cumulative loss position in recent years, our reversal of temporary differences, and our expectation to generate sufficient future taxable income. We use the liability method in determining our provision and liabilities for our income taxes, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates.

Stock-based compensation arrangements – The fair value of stock options is estimated on the date of grant using the Black-Scholes option pricing model. The model employs various assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock option award. Of the required assumptions, the expected volatility of our stock price and the stock price in relation to the strike price have the most significant impact on the fair value calculation. We have utilized historical data and analyzed current information which reasonably support these assumptions.

The fair value of our restricted stock awards, restricted stock units and Director restricted stock units is determined based on the market value of our common stock on the date of grant. Restricted Stock Awards, restricted stock units, and Director restricted stock units are removed from Treasury Stock at grant, vesting, and distribution, respectively.

The fair value of our cash-settled stock-based performance units is estimated using the Monte Carlo simulation method. Since these awards are settled in cash at the end of a defined performance period, they are classified as a liability and are re-measured quarterly until settlement. The fair value of our stock-settled stock-based performance units is estimated using the Monte Carlo simulation method at grant date only. Since these awards are settled in stock, they are classified as equity.

Our stock-based compensation expense is recognized based on management's best estimate of the awards that are expected to vest, using the straight-line attribution method for all service-based awards with a graded vesting feature. If actual forfeiture results are different than expected, adjustments to recognized compensation expense may be required in future periods.

2. Accounting Standards

Not Yet Adopted

Financial instruments – credit losses

In June 2016, the FASB issued a new accounting standards update that changes the impairment model for trade receivables, net investments in leases, debt securities, loans and certain other instruments. The standard requires the use of a forward-looking "expected loss" model as opposed to the current "incurred loss" model. This standard is effective for us in the first quarter of 2020 and will be adopted on a modified retrospective basis through a cumulative-effect adjustment to retained earnings as of the beginning of the adoption period. The adoption of this standard did not result in a material impact on our consolidated results of operations, financial position and cash flows.

Recently Adopted

Lease accounting standard

In February 2016, the FASB issued a new leasing accounting standard, which modified the definition of a lease and established comprehensive accounting and financial reporting requirements for leasing arrangements. It requires lessees to recognize a lease liability and a right-of-use ("ROU") asset for all leases, including operating leases, with a term of greater than 12 months on the balance sheet. On January 1, 2019, we adopted the new lease accounting standard using the modified retrospective method and applied to all leases that existed as of that date. It does not apply to leases to explore for or use minerals, oil, natural gas and similar non-regenerative resources, including the intangible right to explore for those natural resources and rights to use the land in which those natural resources are contained. As a result of the adoption, we recorded a cumulative-effect adjustment to stockholders' equity of $31 million. We continue presenting all prior comparative periods without any restatements. See **Note 13** for further information.

Hedge accounting standard

In August 2017, the FASB issued a new accounting standards update that amends the hedge accounting model to enable entities to hedge certain financial and nonfinancial risk attributes previously not allowed. The amendment also reduces the overall complexity of documenting, assessing and measuring hedge effectiveness. This standard was effective for us in the first quarter of 2019. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

3. Income (loss) and Dividends per Common Share

Basic income (loss) per share is based on the weighted average number of common shares outstanding. Diluted income (loss) per share assumes exercise of stock options in all periods, provided the effect is not antidilutive. The per share calculations below exclude $6 million, $6 million and 11 million stock options in 2019, 2018 and 2017 that were antidilutive.

	Year Ended December 31,		
(In millions, except per share data)	**2019**	**2018**	**2017**
Income (loss) from continuing operations	$ 480	$ 1,096	$ (830)
Loss from discontinued operations	—	—	(4,893)
Net income (loss)	$ 480	$ 1,096	$ (5,723)
Weighted average common shares outstanding	810	846	850
Effect of dilutive securities	—	1	—
Weighted average common shares, diluted	810	847	850
Per basic share:			
Income (loss) from continuing operations	$ 0.59	$ 1.30	$ (0.97)
Loss from discontinued operations	$ —	$ —	$ (5.76)
Net income (loss)	$ 0.59	$ 1.30	$ (6.73)
Per diluted share:			
Income (loss) from continuing operations	$ 0.59	$ 1.29	$ (0.97)
Loss from discontinued operations	$ —	$ —	$ (5.76)
Net income (loss)	$ 0.59	$ 1.29	$ (6.73)
Dividends per share	$ 0.20	$ 0.20	$ 0.20

4. Acquisitions

2019 – United States Segment

In the fourth quarter of 2019, we acquired approximately 40,000 net acres in a Texas Delaware oil play in West Texas from multiple sellers for $106 million. We accounted for these transactions as an asset acquisition, allocating the purchase price to unproved property within property, plant and equipment.

During the fourth quarter of 2019, we acquired a 100% working interest in approximately 18,000 net acres in the Eagle Ford from Rocky Creek Resources, LLC and RCR Midstream, LLC for $191 million in cash, subject to post-closing adjustments. We accounted for this transaction as a business combination, with the entire purchase price allocated between proved property, unproved property, and other assets, all within property, plant and equipment.

The fair values of the assets acquired were measured using the market approach, specifically the market comparable technique. The fair values were based on market-corroborated inputs, which were derived from observable market data; such inputs represent Level 2 inputs. As the acquisition date was December 31, 2019, there is not a pro forma effect of this transaction on our consolidated statement of income.

2017 – United States Segment

In the fourth quarter of 2017, we closed on our acquisition of additional acreage in the Northern Delaware basin of New Mexico from a private seller for $63 million in cash and accounted for this transaction as an asset acquisition, allocating the purchase price to unproved property within property, plant and equipment.

In the second quarter of 2017, we closed on two acquisitions which included approximately 91,000 net acres in the Permian basin of New Mexico. The first acquisition with BC Operating, Inc. and other entities closed for approximately $1.1 billion in cash and the second acquisition with Black Mountain Oil & Gas and other private sellers closed for approximately $700 million in cash. These acquisitions were paid with cash on hand and accounted for as asset acquisitions, with substantially all of the purchase price allocated to unproved property within property, plant and equipment.

5. Dispositions

United States Segment

In the third quarter of 2018, we closed on the sale of non-core, non-operated conventional properties, primarily in the Gulf of Mexico, for combined net proceeds of $16 million, before closing adjustments. A pre-tax gain of $32 million was recognized in the third quarter of 2018.

International Segment

On July 1, 2019, we closed on the sale of our U.K. business (Marathon Oil U.K. LLC and Marathon Oil West of Shetlands Limited), for proceeds of $95 million which reflects the assumption by RockRose Energy PLC ("RockRose") of the U.K. business' working capital and cash equivalent balances of approximately $345 million on December 31, 2018. During the third quarter of 2019, we recorded a $6 million liability and corresponding expense related to the estimated fair value of our exposure to surety bonds we continued to hold that guaranteed decommissioning liabilities of Marathon Oil U.K. LLC. In November 2019, RockRose posted replacement security and accordingly, we reversed the aforementioned $6 million (see **Note 25** for further detail). Income before taxes relating to our U.K. business for the year ended December 31, 2019 and 2018, was $33 million and $261 million, respectively. See **Note 12** and **Note 19** for additional details on U.K. ARO and the defined benefit pension plan as it relates to this disposition.

In the second quarter of 2019, we closed on the sale of our 15% non-operated interest in the Atrush block in Kurdistan for proceeds of $63 million, before closing adjustments. This property was classified as held for sale in the consolidated balance sheet at December 31, 2018, with total assets of $58 million and total liabilities of $17 million.

In the first quarter of 2018, we closed on the sale of our subsidiary, Marathon Oil Libya Limited, which held our 16.33% non-operated interest in the Waha concessions in Libya, to a subsidiary of Total S.A. (Elf Aquitaine SAS) for proceeds of approximately $450 million, excluding closing adjustments, and recognized a pre-tax gain of $255 million.

Canadian Business – Discontinued Operations

On May 31, 2017 we closed on the sale of our Canadian business, which included our 20% non-operated interest in the AOSP to Shell and Canadian Natural Resources Limited for $2.5 billion, excluding closing adjustments. Under the terms of the agreement, $1.8 billion was paid to us upon closing. At closing we received two notes receivable for a combined $750 million for the remaining proceeds, which was received in the first quarter of 2018. In the first quarter of 2017, we recorded a non-cash impairment charge of $6.6 billion (after-tax of $4.96 billion) primarily related to the property, plant and equipment of our Canadian business. This impairment was recorded for excess net book value over anticipated sales proceeds less costs to sell. Fair values of assets held for sale were determined based upon the anticipated sales proceeds less costs to sell, which resulted in a level 2 classification. As the effective date of the transaction was January 1, 2017, we recorded a loss on sale of $43 million during the second quarter of 2017 due to results of operations from our Canadian business that were transferred to the buyer upon closing.

Our Canadian business is reflected as discontinued operations in the consolidated statements of income and the consolidated statements of cash flows for all periods presented. The following table contains select amounts reported in our historical consolidated statements of income and consolidated statements of cash flows as discontinued operations:

(In millions)	Year Ended December 31, 2017
Total revenue and other income	$ 431
Net loss on disposal of assets	(43)
Total revenues and other income	388
Costs and expenses:	
Production	254
Depreciation, depletion and amortization	40
Impairments	6,636
Other	25
Total costs and expenses	6,955
Pretax loss from discontinued operations	(6,567)
Benefit for income taxes	(1,674)
Loss from discontinued operations	$ (4,893)

(In millions)	Year Ended December 31, 2017
Cash flow from discontinued operations:	
Operating activities	$ 141
Investing activities	(13)
Changes in cash included in current assets held for sale	2
Net increase in cash and cash equivalents of discontinued operations	$ 130

6. Revenues

The majority of our revenues are derived from the sale of crude oil and condensate, NGLs and natural gas under spot and term agreements with our customers in the United States and various international locations.

The following tables present our revenues from contracts with customers disaggregated by product type and geographic areas.

United States

	Year Ended December 31, 2019					
(In millions)	Eagle Ford	Bakken	Oklahoma	Northern Delaware	Other U.S.	Total
Crude oil and condensate	$ 1,358	$ 1,686	$ 425	$ 316	$ 102	$ 3,887
Natural gas liquids	114	46	116	26	5	307
Natural gas	121	39	156	16	17	349
Other	7	—	—	—	52	59
Revenues from contracts with customers	$ 1,600	$ 1,771	$ 697	$ 358	$ 176	$ 4,602

	Year Ended December 31, 2018					
(In millions)	Eagle Ford	Bakken	Oklahoma	Northern Delaware	Other U.S.	Total
Crude oil and condensate	$ 1,554	$ 1,568	$ 426	$ 235	$ 164	$ 3,947
Natural gas liquids	205	62	181	38	9	495
Natural gas	145	38	184	20	26	413
Other	8	—	—	—	23	31
Revenues from contracts with customers	$ 1,912	$ 1,668	$ 791	$ 293	$ 222	$ 4,886

International

	Year Ended December 31, 2019			
(In millions)	E.G.	U.K.	Other International	Total
Crude oil and condensate	$ 271	$ 107	$ 20	$ 398
Natural gas liquids	4	1	—	5
Natural gas	32	12	—	44
Other	—	14	—	14
Revenues from contracts with customers	$ 307	$ 134	$ 20	$ 461

	Year Ended December 31, 2018				
(In millions)	E.G.	U.K.	Libya	Other International	Total
Crude oil and condensate	$ 342	$ 282	$ 187	$ 77	$ 888
Natural gas liquids	4	5	—	—	9
Natural gas	37	40	9	—	86
Other	1	32	—	—	33
Revenues from contracts with customers	$ 384	$ 359	$ 196	$ 77	$ 1,016

In 2019, sales to Marathon Petroleum Corporation, Flint Hills Resources, Valero Marketing and Supply, and Shell Trading and each of their respective affiliates, accounted for approximately 13%, 13%, 11%, and 10%, respectively, of our total revenues. In 2018, sales to Valero Marketing and Supply and Flint Hills Resources and their respective affiliates, each accounted for approximately 11% of our total revenues. In 2017, sales to Vitol and their respective affiliates accounted for approximately 10% of our total revenues.

The pricing in our hydrocarbon sales agreements are variable, determined using various published benchmarks which are adjusted for negotiated quality and location differentials. As a result, revenue collected under our agreements with customers is highly dependent on the market conditions and may fluctuate considerably as the hydrocarbon market prices rise or fall. Typically, our customers pay us monthly, within a short period of time after we deliver the hydrocarbon products. As such, we do not have any financing element associated with our contracts. We do not have any issues related to returns or refunds, as product specifications are standardized for the industry and are typically measured when transferred to a common carrier or midstream entity, and other contractual mechanisms (e.g., price adjustments) are used when products do not meet those specifications.

In limited cases, we may also collect advance payments from customers as stipulated in our agreements; payments in excess of recognized revenue are recorded as contract liabilities on our consolidated balance sheet.

Under our hydrocarbon sales agreements, the entire consideration amount is variable either due to pricing and/or volumes. We recognize revenue in the amount of variable consideration allocated to distinct units of hydrocarbons transferred to a customer. Such allocation reflects the amount of total consideration we expect to collect for completed deliveries of hydrocarbons and the terms of variable payment relate specifically to our efforts to satisfy the performance obligations under these contracts. Our performance obligations under our hydrocarbon sales agreements are to deliver either the entire production from the dedicated wells or specified contractual volumes of hydrocarbons.

We often serve as the operator for jointly owned oil and gas properties. As part of this role, we perform activities to explore, develop and produce oil and gas properties in accordance with the joint operating arrangements. Other working interest owners reimburse us for costs incurred based on our agreements. We determined that these activities are not performed as part of customer relationships and such reimbursements will continue to not be recorded as revenues within the scope of the revenue accounting standard.

In addition, we commonly market the share of production belonging to other working interest owners as the operator of jointly owned oil and gas properties. We concluded that those marketing activities are carried out as part of the collaborative arrangement. Therefore, we act as a principal only in regards to the sale of our share of production and recognize revenue for the volumes associated with our net production.

Crude oil and condensate

For the crude sales agreements, we satisfy our performance obligations and recognize revenue once customers take control of the crude at the designated delivery points, which include pipelines, trucks or vessels.

Natural gas and NGLs

When selling natural gas and NGLs, we engage midstream entities to process our production stream by separating natural gas from the NGLs. Frequently, these midstream entities also purchase our natural gas and NGLs under the same agreements. In these situations, we determined the performance obligation is complete and satisfied at the tailgate of the processing plant when the natural gas and NGLs become identifiable and measurable products. We determined the plant tailgate is the point in time where control is transferred to midstream entities and they are entitled to significant risks and rewards of ownership of the natural gas and NGLs.

The amounts due to midstream entities for gathering and processing services are recognized as shipping and handling cost, since we make those payments in exchange for distinct services. Under some of our natural gas processing agreements, we have an option to take the processed natural gas and NGLs in-kind and sell to customers other than the processing company. In those circumstances, our performance obligations are complete after delivering the processed hydrocarbons to the customer at the designated delivery points, which may be the tailgate of the processing plant or an alternative delivery point requested by the customer.

We have "percentage-of-proceeds" arrangements with some midstream entities where they retain a percentage of the proceeds collected for selling our processed natural gas and NGLs as compensation for their processing and marketing services. We recognize revenue for the gross sales volumes and recognize the proceeds retained by midstream companies as shipping and handling cost.

Contract receivables and liabilities

The following table provides information about receivables and contract assets (liabilities) from contracts with customers.

	December 31,	
(In millions)	**2019**	**2018**
Receivables from contracts with customers, included in receivables, less reserves	$ 837	$ 714
Contract asset (liability)	$ —	$ (1)

The contract liability balance on January 1, 2019 relates to the advance consideration received from customers for crude oil sales and processing services in the U.K. Subsequent to the sale of our U.K. business, we no longer hold this contract liability.

Changes in the contract asset (liability) balance during the period are as follows.

(In millions)	**Year Ended December 31, 2019**
Contract asset (liability) balance as of January 1, 2019	$ (1)
Revenue recognized as performance obligations are satisfied	74
Amounts invoiced to customers	(52)
Contract asset (liability) transferred to buyer[(a)]	(21)
Contract asset (liability) balance as of December 31, 2019	$ —

(a) Refer to Note 5 for further information on the sale of our U.K. business.

7. Segment Information

We have two reportable operating segments. Both of these segments are organized and managed based upon geographic location and the nature of the products and services offered.

- United States ("U.S.") – explores for, produces and markets crude oil and condensate, NGLs and natural gas in the United States
- International ("Int'l") – explores for, produces and markets crude oil and condensate, NGLs and natural gas outside of the United States as well as produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

Segment income represents income which excludes certain items not allocated to our operating segments, net of income taxes. A portion of our corporate and operations general and administrative support costs are not allocated to the operating segments. These unallocated costs primarily consist of employment costs (including pension effects), professional services, facilities and other costs associated with corporate and operations support activities. Additionally, items which affect comparability such as: gains or losses on dispositions, certain property impairments, certain exploration expenses relating to a strategic decision to exit conventional exploration, unrealized gains or losses on commodity derivative instruments, pension settlement losses or other items (as determined by the CODM) are not allocated to operating segments.

As discussed in **Note 5**, the sale of our Canadian business in 2017 is reflected as discontinued operations and is excluded from segment information in all periods presented.

(In millions)	Year Ended December 31, 2019			
	U.S.	**Int'l**	**Not Allocated to Segments**	**Total**
Revenues from contracts with customers	$ 4,602	$ 461	$ —	$ 5,063
Net gain (loss) on commodity derivatives	52	—	(124) [b]	(72)
Income from equity method investments	—	87	—	87
Net gain on disposal of assets	—	—	50 [c]	50
Other income	13	9	40	62
Less costs and expenses:				
Production	588	126	(2)	712
Shipping, handling and other operating	561	26	18	605
Exploration	149	—	—	149
Depreciation, depletion and amortization	2,250	121	26	2,397
Impairments	—	—	24 [d]	24
Taxes other than income	311	—	—	311
General and administrative	127	25	204	356
Net interest and other	—	—	244	244
Other net periodic benefit costs	—	(3)	— [e]	(3)
Loss on early extinguishment of debt	—	—	3	3
Income tax provision (benefit)	6	29	(123)	(88)
Segment income (loss)	$ 675	$ 233	$ (428)	$ 480
Total assets	$ 17,781	$ 1,530	$ 934	$ 20,245
Capital expenditures[a]	$ 2,550	$ 16	$ 25	$ 2,591

(a) Includes accruals and excludes acquisitions.
(b) Unrealized loss on commodity derivative instruments (see **Note 15**).
(c) Primarily related to the sale of our working interest in the Droshky field (Gulf of Mexico) and the sale of our U.K. business (see **Note 5**).
(d) Primarily a result of anticipated sales of non-core proved properties in our International and United States segments (see **Note 11**).
(e) Includes pension settlement loss of $12 million (see **Note 19**).

(In millions)	Year Ended December 31, 2018 U.S.	Int'l	Not Allocated to Segments	Total
Revenues from contracts with customers	$ 4,886	$ 1,016	$ —	$ 5,902
Net gain (loss) on commodity derivatives	(281)	—	267 [(b)]	(14)
Income from equity method investments	—	225	—	225
Net gain on disposal of assets	—	—	319 [(c)]	319
Other income	16	12	122 [(d)]	150
Less costs and expenses:				
Production	625	215	2	842
Shipping, handling and other operating	499	70	6	575
Exploration	246	3	40 [(e)]	289
Depreciation, depletion and amortization	2,217	197	27	2,441
Impairments	—	—	75 [(f)]	75
Taxes other than income	301	—	(2)	299
General and administrative	146	32	216	394
Net interest and other	—	—	226	226
Other net periodic benefit costs	—	(9)	23 [(g)]	14
Income tax provision (benefit)	(21)	272	80	331
Segment income	$ 608	$ 473	$ 15	$ 1,096
Total assets	$ 17,321	$ 2,083	$ 1,917	$ 21,321
Capital expenditures[(a)]	$ 2,620	$ 39	$ 26	$ 2,685

(a) Includes accruals and excludes acquisitions.
(b) Unrealized gain on commodity derivative instruments (see **Note 15**).
(c) Primarily related to the gain on sale of our Libya subsidiary (see **Note 5**).
(d) Primarily a reduction of asset retirement obligations in our International segment (see **Note 12**).
(e) Primarily related to dry well expense and unproved property impairments associated with the Rodo well in Alba Block Sub Area B, offshore E.G. (see **Note 10**).
(f) Due to the anticipated sales of certain non-core proved properties in our International and United States segments (see **Note 11**).
(g) Includes pension settlement loss of $21 million (see **Note 19**).

	Year Ended December 31, 2017			
(In millions)	U.S.	Int'l	Not Allocated to Segments	Total
Revenues from contracts with customers	$ 3,093	$ 1,154	$ —	$ 4,247
Net gain (loss) on commodity derivatives	45	—	(81) (b)	(36)
Marketing revenues	29	133	—	162
Income from equity method investments	—	256	—	256
Net gain on disposal of assets	1	—	57 (c)	58
Other income	12	6	60	78
Less costs and expenses:				
Production	476	239	1	716
Marketing costs	36	132	—	168
Shipping, handling and other operating	354	77	—	431
Exploration	154	5	250 (d)	409
Depreciation, depletion and amortization	2,011	328	33	2,372
Impairments	4	—	225 (e)	229
Taxes other than income	173	—	10	183
General and administrative	119	30	222	371
Net interest and other	—	—	270 (f)	270
Other net periodic benefit costs	—	(8)	27 (g)	19
Loss on early extinguishment of debt	—	—	51 (h)	51
Income tax provision	1	372	3	376
Segment income (loss)	$ (148)	$ 374	$ (1,056)	$ (830)
Total assets	$ 16,863	$ 4,201	$ 948	$ 22,012
Capital expenditures[(a)]	$ 2,081	$ 42	$ 27	$ 2,150

(a) Includes accruals and excludes acquisitions.
(b) Unrealized loss on commodity derivative instruments (see **Note 15**).
(c) Primarily related to the sale of certain conventional assets in Oklahoma and Colorado (see **Note 5**).
(d) Primarily related to unproved property impairments associated with certain non-core properties within our International segment (see **Note 11**).
(e) Primarily related to proved property impairments associated with certain non-core properties within our International segment (see **Note 11**).
(f) Includes a gain of $46 million resulting from the termination of our forward starting interest rate swaps (see **Note 15**).
(g) Includes pension settlement loss of $32 million (see **Note 19**).
(h) Primarily related to the make-whole call provisions paid upon redemption of our senior unsecured notes (see **Note 17**).

The following summarizes property, plant and equipment and equity method investments.

	December 31,	
(In millions)	2019	2018
United States	$ 16,507	$ 16,094
Equatorial Guinea	1,156	1,333
Other international[(a)]	—	122
Total long-lived assets	$ 17,663	$ 17,549

(a) The decrease in 2019 is due to the sale of our non-operated interest in the Atrush block in Kurdistan and the sale of our U.K. business (see **Note 5**).

8. Income Taxes

Income (loss) from continuing operations before income taxes were:

	Year Ended December 31,		
(In millions)	2019	2018	2017
United States	$ 43	$ 642	$ (783)
Foreign	349	785	329
Total	$ 392	$ 1,427	$ (454)

Income tax provisions (benefits) for continuing operations were:

	Year Ended December 31,								
	2019			2018			2017		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ (116)	$ (3)	$ (119)	$ 6	$ —	$ 6	$ (32)	$ 41	$ 9
State and local	4	3	7	(1)	(23)	(24)	(14)	2	(12)
Foreign	58	(34)	24	274	75	349	483	(104)	379
Total	$ (54)	$ (34)	$ (88)	$ 279	$ 52	$ 331	$ 437	$ (61)	$ 376

A reconciliation of the federal statutory income tax rate applied to income (loss) from continuing operations before income taxes to the provision (benefit) for income taxes follows:

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Total pre-tax income (loss) from continuing operations	$ 392	$ 1,427	$ (454)
Total income tax expense (benefit)	$ (88)	$ 331	$ 376
Effective income tax rate (benefit) on continuing operations	(22)%	23%	83%
Income taxes at the statutory tax rate[a][b]	$ 83	$ 300	$ (159)
Effects of foreign operations	(29)	214	140
Adjustments to valuation allowances	(28)	(177)	446
State income taxes	11	(17)	(19)
Tax law change	—	—	(35)
Other federal tax effects	(125)	11	3
Income tax expense (benefit) on continuing operations	$ (88)	$ 331	$ 376

[a] Includes income tax benefits primarily related to our U.S. federal income taxes where we have maintained a full valuation allowance since December 2016.
[b] As a result of the Tax Reform Legislation (see below), the U.S. corporate income tax rate was reduced to 21% in 2018. The U.S. corporate income tax rate was 35% in 2017.

The effective income tax rate is influenced by a variety of factors including the geographic and functional sources of income and the relative magnitude of these sources of income. The difference between the total provision and the sum of the amounts allocated to segments is reported in the "Not Allocated to Segments" column of the tables in **Note 7**.

Effects of foreign operations – The effects of foreign operations decreased our tax expense in 2019 due to tax benefits related to our U.K. operations and pre-tax income in jurisdictions with effective tax rates lower than the U.S. The effects of foreign operations increased our tax expense in 2018 and 2017 due to the mix of pre-tax income between high and low tax jurisdictions, including Libya where the tax rate was 93.5%. Excluding Libya, the effective tax rates on continuing operations would be an expense of 14% in 2018 and 5% in 2017. As a result of the sale of our Libya subsidiary in the first quarter of 2018, we do not expect to incur further tax expense related to Libya.

Change in tax law – On December 22, 2017, the U.S. enacted the Tax Cuts and Jobs Act (the "Tax Reform Legislation"). Tax Reform Legislation, which is also commonly referred to as "U.S. tax reform", significantly changing U.S. corporate income tax laws by, among other things, reducing the U.S. corporate income tax rate to 21% starting in 2018, and repeal of the corporate alternative minimum tax ("AMT"), and a one-time deemed repatriation of accumulated foreign earnings. In the fourth quarter of 2017, we remeasured our deferred taxes at 21%, in accordance with U.S. GAAP. The impact of the remeasurement on our federal deferred tax assets and liabilities was equally offset by an adjustment to our valuation allowance with no material impact to current year earnings. In accordance with Staff Accounting Bulletin No. 118 ("SAB 118") we finalized our tax position in the fourth quarter of 2018 with no material changes made to positions considered provisional as of December 31, 2017.

Other federal tax effects – The decrease in other federal tax effects is primarily related to the settlement of the 2010-2011 U.S. Federal Tax Audit ("IRS Audit") in the first quarter of 2019. The release of the accrued tax positions resulted in a $126 million tax benefit, primarily related to AMT credits, see **Note 25** for further detail.

Deferred tax assets and liabilities resulted from the following:

	Year Ended December 31,	
(In millions)	2019	2018
Deferred tax assets:		
Employee benefits	$ 90	$ 75
Operating loss carryforwards	1,685	1,304
Capital loss carryforwards	1	2
Foreign tax credits	611	611
Other	27	4
Subtotal	2,414	1,996
Valuation allowance	(699)	(721)
Total deferred tax assets	1,715	1,275
Deferred tax liabilities:		
Property, plant and equipment	1,861	1,018
Accrued revenue	40	60
Other	—	3
Total deferred tax liabilities	1,901	1,081
Net deferred tax liabilities	$ 186	$ —
Net deferred tax assets	$ —	$ 194

Operating loss carryforwards – At December 31, 2019, our operating loss carryforwards, relating to tax years beginning prior to January 1, 2018, before valuation allowance, include $655 million from the U.S. that expire in 2035 - 2037. Our operating loss carryforwards in the U.S. for tax years beginning after December 31, 2017, before our valuation allowance, include $829 million which can be carried forward indefinitely. Foreign operating loss carryforwards include $20 million that begin to expire in 2020. State operating loss carryforwards of $181 million expire in 2020 through 2038.

Foreign tax credits – At December 31, 2019, we reflect foreign tax credits of $611 million, which will expire in years 2022 through 2026.

Valuation allowances – At December 31, 2019, we reflect a valuation allowance in our consolidated balance sheet of $699 million against our net deferred tax assets in various jurisdictions in which we operate. The decrease in valuation allowance primarily relates to current year activity.

Property, plant and equipment – At December 31, 2019, we reflected a deferred tax liability of $1.9 billion. The increase primarily relates to the sale of our U.K. business and corresponding reduction in the asset retirement obligations and current year activity in the U.S.

Net deferred tax assets and liabilities were classified in the consolidated balance sheets as follows:

	December 31,	
(In millions)	2019	2018
Assets:		
Other noncurrent assets	$ —	$ 393
Liabilities:		
Noncurrent deferred tax liabilities	186	199
Net deferred tax liabilities	$ 186	$ —
Net deferred tax assets	$ —	$ 194

We are routinely undergoing examinations in the jurisdictions in which we operate. As of December 31, 2019, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[(a)]	2008-2018
Equatorial Guinea	2007-2018

(a) Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2019	2018	2017
Beginning balance	$ 263	$ 126	$ 66
Additions for tax positions of prior years	13	152	83
Reductions for tax positions of prior years	(152)	(15)	(3)
Settlements	(111)	—	(20)
Ending balance	$ 13	$ 263	$ 126

If the unrecognized tax benefits as of December 31, 2019 were recognized, $13 million would affect our effective income tax rate. As of December 31, 2019, there are $5 million uncertain tax positions for which it is reasonably possible that the amount could significantly change during the next twelve months. During the first quarter of 2019, we withdrew our appeal related to the Brae area decommissioning costs in the U.K., thus the uncertain tax positions previously established are now considered effectively settled with no tax expense or benefit impact. Also, in the first quarter of 2019, we settled the 2010-2011 IRS Audit, resulting in a tax benefit of $126 million. See **Note 25** for further detail.

Pursuant to the Tax Sharing Agreement we entered into with Marathon Petroleum Corporation ("MPC") in connection with the 2011 spin-off transaction, MPC agreed to indemnify us for certain liabilities. In addition to the benefit from the settlement of the IRS Audit in the first quarter of 2019, we recorded a current receivable and other income of $42 million for indemnity payments due from MPC for tax expense and interest we had previously recognized. The indemnity relates to tax and interest allocable to MPC as a result of the IRS Audit. During the second quarter of 2019, we paid the IRS and were subsequently reimbursed by MPC for settlement of their indemnity obligation.

Interest and penalties are recorded as part of the tax provision and were $6 million, $2 million and $27 million related to unrecognized tax benefits in 2019, 2018 and 2017. As of December 31, 2019 and 2018, $3 million and $27 million of interest and penalties were accrued related to income taxes.

9. Inventories

Crude oil and natural gas are recorded at weighted average cost and carried at the lower of cost or net realizable value. Supplies and other items consist principally of tubular goods and equipment which are valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate.

	December 31,	
(In millions)	2019	2018
Crude oil and natural gas	$ 10	$ 11
Supplies and other items	62	85
Inventories	$ 72	$ 96

10. Property, Plant and Equipment

(In millions)	December 31, 2019	December 31, 2018
United States	$ 16,427	$ 16,011
International[(a)]	493	710
Not allocated to segments	80	83
Net property, plant and equipment	$ 17,000	$ 16,804

(a) The International decrease is due to dispositions of our non-operated interest in the Atrush block in Kurdistan and our U.K. business during 2019 (see **Note 5**).

At December 31, 2019, 2018 and 2017 we had total deferred exploratory well costs as follows:

(In millions)	December 31, 2019	2018	2017
Amounts capitalized less than one year after completion of drilling	$ 278	$ 297	$ 263
Amounts capitalized greater than one year after completion of drilling	—	—	32
Total deferred exploratory well costs	$ 278	$ 297	$ 295
Number of projects with costs capitalized greater than one year after completion of drilling	—	—	1

(In millions)	2019	2018	2017
Beginning balance	$ 297	$ 295	$ 249
Additions	218	262	212
Charges to expense[(a)]	(5)	(35)	(64)
Transfers to development	(230)	(197)	(102)
Dispositions[(b)]	(2)	(28)	—
Ending balance	$ 278	$ 297	$ 295

(a) 2018 includes $32 million related to the Rodo well in Alba Block Sub Area B, offshore E.G. 2017 includes $64 million as a result of our agreement to sell Diaba License G4-223 in the Republic of Gabon (see **Note 11** for further detail).
(b) 2018 includes the sale of our Libya subsidiary.

We had no exploratory well costs capitalized greater than one year as of December 31, 2019 and December 31, 2018.

11. Impairments

The following table summarizes impairment charges of proved properties from continuing operations. Additionally, it presents the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

	2019		2018		2017	
(In millions)	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Long-lived assets held for use	$ 56	$ 24	$ 113	$ 75	$ 179	$ 229

- 2019 – Impairments of $24 million, to an aggregate fair value of $56 million, were primarily a result of proved property impairments primarily as a result of anticipated sales for certain non-core proved properties in our United States segment and the sale of our non-operated interest in the Atrush block (Kurdistan) in our International segment. The related fair value was measured using the market approach, based upon anticipated sales proceeds less costs to sell which resulted in a Level 2 classification.
- 2018 – Impairments in our International and United States segments of $75 million, to a fair value of $113 million, were largely the result of anticipated sales for certain non-core proved properties. The related fair value measurement utilized the market approach, based upon anticipated sales proceeds less costs to sell which resulted in a Level 2 classification.

- 2017 – Impairments in our International segment were primarily a result of lower forecasted long-term commodity prices and the anticipated sales of certain non-core proved properties of $136 million, to an aggregate fair value of $103 million. These fair values were measured using the market approach, based upon either anticipated sales proceeds less costs to sell or a market comparable sales price per boe which resulted in a Level 2 classification.

  Impairments in our United States segment were $89 million, to an aggregate fair value of $76 million, and related to Gulf of Mexico and certain conventional Oklahoma assets primarily as a result of lower forecasted long-term commodity prices. The fair values were measured using an income approach based upon internal estimates of future production levels, prices and discount rate. Inputs to the fair value measurement include reserve and production estimates made by our reservoir engineers, estimated future commodity prices adjusted for quality and location differentials and forecasted operating expenses for the remaining estimated life of the reservoir which resulted in a Level 3 classification.

See **Note 5** for discussion of the divestitures in further detail and **Note 7** for relevant detail regarding segment presentation.

12. Asset Retirement Obligations

Asset retirement obligations primarily consist of estimated costs to remove, dismantle and restore land at the end of oil and gas production operations. Changes in asset retirement obligations for the periods ended December 31 were as follows:

(In millions)	2019	2018
Beginning balance	$ 1,145	$ 1,483
Incurred liabilities, including acquisitions	34	21
Settled liabilities, including dispositions	(1,110)	(117)
Accretion expense (included in depreciation, depletion and amortization)	31	70
Revisions of estimates	46	(204)
Held for sale[a]	108	(108)
Ending balance[b]	$ 254	$ 1,145

[a] In the fourth quarter 2018, we entered into an agreement to sell our working interest in the Droshky field (Gulf of Mexico), including our $98 million asset retirement obligation; this transaction closed during the first quarter of 2019.
[b] $944 million of the 2018 ending balance relates to our asset retirement obligations in the U.K., the sale of which closed in 2019.

2019

- *Settled liabilities* primarily relates to the sale of our U.K. business, which closed during the third quarter of 2019, and the sale of the Droshky field (Gulf of Mexico).
- *Held for sale* reflects a transfer to settled liabilities during 2019. This transfer was primarily related to the Droshky field (Gulf of Mexico) which was considered held for sale at year-end 2018 and closed in the first quarter of 2019.
- *Ending balance* includes $11 million classified as short-term at December 31, 2019.

2018

- *Settled liabilities* include dispositions, primarily related to the sale of non-core, non-operated conventional properties in the Gulf of Mexico as well as retirements in the U.K.
- *Revisions of estimates* were primarily due to the acceleration of U.K. abandonment activities to capture favorable market conditions and lower estimated abandonment costs.
- *Held for sale* primarily related to the Droshky field, which was considered held for sale at year-end 2018.
- *Ending balance* primarily relates to the U.K. and includes $64 million classified as short-term at December 31, 2018.

13. Leases

Supplemental balance sheet information related to leases was as follows:

(In millions)		December 31, 2019
Operating Leases:	**Balance Sheet Location:**	
ROU asset	Other noncurrent assets	$ 199
Current portion of long-term lease liability	Other current liabilities	$ 101
Long-term lease liability	Deferred credits and other liabilities	$ 107

In determining our ROU assets and long-term lease liabilities, the new lease standard requires certain accounting policy decisions, while also providing a number of optional practical expedients for transition accounting. Our accounting policies and the practical expedients utilized are summarized below:

- Implemented an accounting policy to not recognize any right-of-use assets and lease liabilities related to short-term leases on the balance sheet.
- Implemented an accounting policy to not separate the lease and nonlease components for all asset classes, except for vessels.
- Elected the package of practical expedients which allows us to not reassess our prior conclusions regarding the lease identification and lease classification for contracts that commenced or expired prior to the effective date.
- Elected the practical expedient pertaining to land easements which allows us to continue accounting for existing agreements under the previous accounting policies as nonlease transactions. Any modifications of existing contracts or new agreements will be assessed under the new lease accounting guidance and may become leases in the future.

We enter into various lease agreements to support our operations including drilling rigs, well fracturing equipment, compressors, buildings, aircraft, vessels, vehicles and miscellaneous field equipment. We primarily act as a lessee in these transactions and all of our existing leases are classified as either short-term or long-term operating leases.

The majority of the drilling rig agreements and all of fracturing equipment agreements are classified as short-term leases based on the noncancellable period for which we have the right to use the equipment and assessment of options present in each agreement. We also incur variable lease costs under these agreements primarily related to chemicals and sand used in fracturing operations or various additional on-demand equipment and labor. The lease costs associated with the drilling rigs and fracturing equipment are primarily capitalized as part of the well costs.

Our long-term leases are comprised of compressors, buildings, drilling rigs, aircraft, vessels, vehicles and miscellaneous field equipment. Our lease agreements may require both fixed and variable payments; none of the variable payments are rate or index-based, therefore only fixed payments were considered for recognizing lease liabilities and ROU assets related to long-term leases. Also, based on our election not to separate the lease and nonlease components, fixed payments related to equipment, crew and other nonlease components are included in the initial measurement of lease liabilities and ROU assets for all asset classes, except for vessels. For vessels, the contractual consideration was allocated between lease and nonlease components based on estimates provided by service providers.

Our leased assets may be used in joint oil and gas operations with other working interest owners. We recognize lease liabilities and ROU assets only when we are the signatory to a contract as an operator of joint properties. Such lease liabilities and ROU assets are determined based on gross contractual obligations. As we use the leased assets for joint operations, we have the contractual right to recover the other working interest owners' share of lease costs. As a result, our lease costs are presented on a net basis, reduced for any costs recoverable from other working interest owners. The table below presents our net lease costs as of December 31, 2019 with the majority of operating lease costs expensed as incurred, while the majority of the short-term and variable lease costs are capitalized into property, plant and equipment.

(In millions)		Year Ended December 31, 2019
Lease costs:		
Operating lease costs[(a)]	$	84
Short-term lease costs[(b)]		321
Variable lease costs[(c)]		107
Total lease costs	$	512
Other information:		
Cash paid for amounts included in the measurement of operating lease liabilities	$	100
ROU assets obtained in exchange for new operating lease liabilities[(d)]	$	293

(a) Represents our net share of the ROU asset amortization and the interest expense.
(b) Represents our net share of lease costs arising from leases of less than one year but longer than one month that were not included in the lease liability.
(c) Represents our net share of variable lease payments that were not included in the lease liability.
(d) Represents the cumulative value of ROU assets recognized at lease inception during the year of 2019. This amount is then amortized as we utilize the ROU asset, the net effect of which is the ending ROU asset of $199 million (first table above).

We use our periodic incremental borrowing rate to discount future contractual payments to their present values. The weighted average lease term and the discount rate relevant to long-term leases were two years and 4% as of December 31, 2019. The remaining annual undiscounted cash flows associated with long-term leases and the reconciliation of these cash flows to the lease liabilities recognized on the consolidated balance sheet is summarized below.

(In millions)		Operating Lease Obligations
2020	$	114
2021		63
2022		35
2023		5
2024		1
Thereafter		—
Total undiscounted lease payments	$	218
Less: amount representing interest		10
Total operating lease liabilities	$	208
Less: current portion of long-term lease liability as of December 31, 2019		101
Long-term lease liability as of December 31, 2019	$	107

At December 31, 2018, future minimum commitments under the previous accounting standard, ASC 840, for operating lease obligations having noncancellable lease terms in excess of one year were as follows:

(In millions)	Operating Lease Obligations	
2019	$	62
2020		54
2021		35
2022		12
2023		5
Thereafter		49
Sublease rentals		—
Total minimum lease payments	$	217

* Future minimum commitments for capital lease obligations were nil as of December 31, 2018.

Our wholly-owned subsidiary, Marathon E.G. Production Limited, is a lessor for residential housing in Equatorial Guinea, which is occupied by EGHoldings, a related party equity method investee – see **Note 23**. The lease was classified as an operating lease and expires in 2024, with a lessee option to extend through 2034. Lease payments are fixed for the entire duration of the agreement at approximately $6 million per year. Our lease income is reported in other income in our consolidated statements of income for all periods presented. The undiscounted cash flows to be received under this lease agreement are summarized below.

(In millions)	Operating Lease Future Cash Receipts	
2020	$	6
2021		6
2022		6
2023		6
2024		6
Thereafter		60
Total undiscounted cash flows	$	90

In 2018, we signed an agreement with an owner/lessor to construct and lease a new build-to-suit office building in Houston, Texas. The new Houston office location is expected to be completed in 2021. The lessor and other participants are providing financing for up to $380 million, to fund the estimated project costs. As of December 31, 2019, project costs incurred totaled approximately $58 million, primarily for land acquisition and initial design costs. The initial lease term is five years and will commence once construction is substantially complete and the new Houston office is ready for occupancy. At the end of the initial lease term, we can negotiate to extend the lease term for an additional five years, subject to the approval of the participants; purchase the property subject to certain terms and conditions; or remarket the property to an unrelated third party. The lease contains a residual value guarantee of approximately 89% of the total acquisition and construction costs.

14. Goodwill

As of December 31, 2019, our consolidated balance sheet included goodwill of $95 million. Goodwill is tested for impairment on an annual basis, or between annual tests when events or changes in circumstances indicate the fair value may have been reduced below its carrying value. Goodwill is tested for impairment at the reporting unit level. Our reporting units are the same as our reporting segments, of which only International includes goodwill. We first assess the qualitative factors in order to determine whether the fair value of our International reporting unit is more likely than not less than its carrying amount. Certain qualitative factors used in our evaluation include, among other things, the results of the most recent quantitative assessment of the goodwill impairment test, macroeconomic conditions; industry and market conditions (including commodity prices and cost factors); overall financial performance; and other relevant entity-specific events. If, after considering these events and circumstances we determined that it is more likely than not that the fair value of the International reporting unit is less than its carrying amount, a quantitative goodwill test is performed. The quantitative goodwill test is performed using a combination of market and income approaches. The market approach references observable inputs specific to us and our industry, such as the price of our common equity, our enterprise value, and valuation multiples of us and our peers from the investor analyst community. The income approach utilizes discounted cash flows, which are based on forecasted assumptions. Key assumptions to the income approach include future liquid hydrocarbon and natural gas pricing, estimated quantities of liquid hydrocarbons and natural gas proved and probable reserves, estimated timing of production, discount rates, future capital requirements, operating expenses and tax rates. The assumptions used in the income approach are consistent with those that management uses to make business decisions. This quantitative goodwill test would represent Level 3 fair value measurements.

During the second quarter of 2019, we performed our annual impairment test of goodwill using the qualitative assessment. Our qualitative assessment considered the significant excess fair value over carrying value in our most recent step 1 test (second quarter 2017) and noted a general improvement in the qualitative factors above. After assessing the totality of the qualitative factors which could have a positive or negative impact on goodwill, our assessment did not indicate that it is more likely than not that the fair value is less than its carrying value. As a result, we concluded that no impairment to goodwill was required for our International reporting unit.

As of December 31, 2019 and 2018 our International segment is the only reporting segment which includes goodwill. The table below displays the allocated beginning goodwill balance of our International segment along with changes in the carrying amount of goodwill for 2019 and 2018:

(In millions)		International
2018		
Beginning balance, gross	$	115
Less: accumulated impairments		—
Beginning balance, net		115
Dispositions[a]		(18)
Impairment		—
Ending balance, net	$	97
2019		
Beginning balance, gross	$	97
Less: accumulated impairments		—
Beginning balance, net		97
Dispositions		(2)
Impairment		—
Ending balance, net	$	95

(a) Primarily related to the sale of our Libya subsidiary (see **Note 5**).

15. Derivatives

See **Note 16** for further information regarding the fair value measurement of derivative instruments. See **Note 1** for discussion of the types of derivatives we may use and the reasons for them. All of our commodity derivatives and interest rate derivatives are/were subject to enforceable master netting arrangements or similar agreements under which we report net amounts. The following tables present the gross fair values of derivative instruments and the reported net amounts along with where they appear on the consolidated balance sheets.

	December 31, 2019			
(In millions)	Asset	Liability	Net Asset (Liability)	Balance Sheet Location
Not Designated as Hedges				
Commodity	$ 9	$ 1	$ 8	Other current assets
Commodity	1	—	1	Other noncurrent assets
Commodity	—	5	(5)	Other current liabilities
Total Not Designated as Hedges	$ 10	$ 6	$ 4	
Cash Flow Hedges				
Interest Rate	$ 2	$ —	$ 2	Other noncurrent assets
Total Designated Hedges	$ 2	$ —	$ 2	
Total	$ 12	$ 6	$ 6	

	December 31, 2018			
(In millions)	Asset	Liability	Net Asset (Liability)	Balance Sheet Location
Not Designated as Hedges				
Commodity	$ 131	$ —	$ 131	Other current assets
Commodity	—	4	(4)	Deferred credits and other liabilities
Total Not Designated as Hedges	$ 131	$ 4	$ 127	

Derivatives Not Designated as Hedges

Terminated Interest Rate Swaps

During the second quarter of 2017, we de-designated forward starting interest rate swaps used to hedge the variations in cash flows related to fluctuations in long term interest rates from debt that was refinanced in the third quarter of 2017. In the third quarter of 2017, we terminated our forward starting interest rate swaps for proceeds of $54 million and recognized a gain of $46 million in net interest. See **Note 17** for further detail.

The following table sets forth the net impact of the terminated forward starting interest rate swap derivatives de-designated as cash flow hedges on other comprehensive income (loss).

(In millions)	Year Ended December 31, 2017
Interest Rate Swaps	
Beginning balance	$ 60
Change in fair value recognized in other comprehensive income	(13)
Reclassification from other comprehensive income	(47)
Ending balance	$ —

Commodity Derivatives

We have entered into multiple crude oil and natural gas derivatives indexed to NYMEX WTI and Henry Hub related to a portion of our forecasted United States sales through 2021. These commodity derivatives consist of three-way collars and basis swaps. Three-way collars consist of a sold call (ceiling), a purchased put (floor) and a sold put. The ceiling price is the maximum we will receive for the contract volumes; the floor is the minimum price we will receive, unless the market price falls below the sold put strike price. In this case, we receive the NYMEX WTI price plus the difference between the floor and the sold put price. These crude oil derivatives were not designated as hedges.

The following table sets forth outstanding derivative contracts as of December 31, 2019 and the weighted average prices for those contracts:

	2020				2021
Crude Oil	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Full Year**
NYMEX WTI Three-Way Collars					
Volume (Bbls/day)	60,000	60,000	60,000	60,000	—
Weighted average price per Bbl:					
Ceiling	$ 66.04	$ 66.04	$ 63.74	$ 63.74	$ —
Floor	$ 55.00	$ 55.00	$ 55.00	$ 55.00	$ —
Sold put	$ 47.67	$ 47.67	$ 48.00	$ 48.00	$ —
Basis Swaps - Argus WTI Midland[(a)]					
Volume (Bbls/day)	15,000	15,000	15,000	15,000	—
Weighted average price per Bbl	$ (0.94)	$ (0.94)	$ (0.94)	$ (0.94)	$ —
Basis Swaps - NYMEX WTI / ICE Brent[(b)]					
Volume (Bbls/day)	5,000	5,000	5,000	5,000	808
Weighted average price per Bbl	$ (7.24)	$ (7.24)	$ (7.24)	$ (7.24)	$ (7.24)
Natural Gas					
Three-Way Collars					
Volume (MMBtu/day)	100,000	—	—	—	—
Weighted average price per MMBtu:					
Ceiling	$ 3.32	$ —	$ —	$ —	$ —
Floor	$ 2.75	$ —	$ —	$ —	$ —
Sold put	$ 2.25	$ —	$ —	$ —	$ —

(a) The basis differential price is indexed against Argus WTI Midland.
(b) The basis differential price is indexed against Intercontinental Exchange ("ICE") Brent and NYMEX WTI.

Between January 1, 2020 and February 10, 2020, we entered into 20,000 bbls/day of three-way collars for 2020 with a ceiling price of $66.37, a floor price of $55.00 and a sold put price of $48.00.

The mark-to-market impact and settlement of these commodity derivative instruments appears in the table below and is reflected in net gain (loss) on commodity derivatives in the consolidated statements of income.

	Year Ended December 31,		
(In millions)	**2019**	**2018**	**2017**
Mark-to-market gain (loss)	$ (124)	$ 267	$ (81)
Net settlements of commodity derivative instruments	$ 52	$ (281)	$ 45

Derivatives Designated as Cash Flow Hedges

During 2019, we entered into forward starting interest rate swaps with a total notional amount of $320 million to hedge variations in cash flows related to the 1-month London Interbank Offered Rate ("LIBOR") component of future lease payments of our future Houston office. These swaps will settle monthly on the same day the lease payment is made with the first swap settlement occurring in January 2022. We expect the first lease payment to commence sometime in the period from December 2021 to May 2022. The last swap will mature on September 9, 2026. See Note 13 for further details regarding the lease of the new Houston office.

The following table presents information about our interest rate swap agreements, including the weighted average LIBOR-based, fixed rate.

	December 31, 2019		December 31, 2018	
(In millions, except fixed rates)	**Aggregate Notional Amount**	**Weighted Average, LIBOR**	**Aggregate Notional Amount**	**Weighted Average, LIBOR**
Interest rate swaps	$ 320	1.514%	$ —	—%

At December 31, 2019, accumulated other comprehensive income included deferred gains of $2 million related to forward starting interest rate swaps. No amounts related to these swaps are expected to impact the consolidated statements of income in the next 12 months.

16. Fair Value Measurements

Fair Values – Recurring

The following tables' present assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2019 and 2018 by hierarchy level.

	December 31, 2019			
(In millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Derivative instruments, assets				
Commodity[(a)]	$ —	$ 7	$ —	$ 7
Interest rate	—	2	—	2
Derivative instruments, assets	$ —	$ 9	$ —	$ 9
Derivative instruments, liabilities				
Commodity[(a)]	$ (3)	$ —	$ —	$ (3)
Derivative instruments, liabilities	$ (3)	$ —	$ —	$ (3)
Total	$ (3)	$ 9	$ —	$ 6

	December 31, 2018			
(In millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Derivative instruments, assets				
Commodity[(a)]	$ 21	$ 106	$ —	$ 127
Derivative instruments, assets	$ 21	$ 106	$ —	$ 127
Derivative instruments, liabilities				
Derivative instruments, liabilities	$ —	$ —	$ —	$ —
Total	$ 21	$ 106	$ —	$ 127

(a) Derivative instruments are recorded on a net basis in our consolidated balance sheet (see **Note 15**).

Commodity derivatives include three-way collars and basis swaps. These instruments are measured at fair value using either a Black-Scholes or a modified Black-Scholes Model. For basis swaps, inputs to the models include only commodity prices and interest rates and are categorized as Level 1 because all assumptions and inputs are observable in active markets throughout the term of the instruments. For three-way collars, inputs to the models include commodity prices, and implied volatility and are categorized as Level 2 because predominantly all assumptions and inputs are observable in active markets throughout the term of the instruments.

The forward starting interest rate swaps are measured at fair value with a market approach using actionable broker quotes, which are Level 2 inputs. See **Note 15** for details on the forward starting interest swaps.

Fair Values – Goodwill

See **Note 14** for detail information relating to goodwill.

Fair Values – Nonrecurring

See **Note 5** and **Note 11** for detail on our fair values for nonrecurring items, such as impairments.

Fair Values – Financial Instruments

Our current assets and liabilities include financial instruments, the most significant of which are receivables, the current portion of our long-term debt and payables. We believe the carrying values of our receivables and payables approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments, (2) our credit rating and (3) our historical incurrence of and expected future insignificance of bad debt expense, which includes an evaluation of counterparty credit risk.

The following table summarizes financial instruments, excluding receivables, payables and derivative financial instruments, and their reported fair values by individual balance sheet line item at December 31, 2019 and 2018.

	December 31,			
	2019		2018	
(In millions)	Fair Value	Carrying Amount	Fair Value	Carrying Amount
Financial assets				
Current assets	$ 4	$ 4	$ 3	$ 3
Other noncurrent assets	26	38	76	81
Total financial assets	$ 30	$ 42	$ 79	$ 84
Financial liabilities				
Other current liabilities	$ 62	$ 90	$ 37	$ 58
Long-term debt, including current portion[(a)]	6,174	5,529	5,469	5,528
Deferred credits and other liabilities	99	86	93	88
Total financial liabilities	$ 6,335	$ 5,705	$ 5,599	$ 5,674

(a) Excludes debt issuance costs.

Fair values of our notes receivable and our financial assets included in other noncurrent assets, and of our financial liabilities included in other current liabilities and deferred credits and other liabilities, are measured using an income approach and most inputs are internally generated, which results in a Level 3 classification. Estimated future cash flows are discounted using a rate deemed appropriate to obtain the fair value.

All of our long-term debt instruments are publicly traded. A market approach, based upon quotes from major financial institutions, which are Level 2 inputs, is used to measure the fair value of our debt.

17. Debt

Revolving Credit Facility

In September 2019, we entered into a fourth amendment to our unsecured revolving credit facility (the “Credit Facility”) to reduce the maximum borrowing from $3.4 billion to $3.0 billion and extended the maturity date by one year to May 28, 2023. As of December 31, 2019, we had no borrowings against our $3.0 billion Credit Facility or under our U.S. commercial paper program that is backed by the Credit Facility.

The Credit Facility includes a covenant requiring that our ratio of total debt to total capitalization not exceed 65% as of the last day of each fiscal quarter. If an event of default occurs, the lenders holding more than half of the commitments may terminate the commitments under the Credit Facility and require the immediate repayment of all outstanding borrowings and the cash collateralization of all outstanding letters of credit under the Credit Facility. As of December 31, 2019, we were in compliance with this covenant with a debt-to-capitalization ratio of 31%.

Long-term debt

The following table details our long-term debt:

	December 31,	
(In millions)	**2019**	**2018**
Senior unsecured notes:		
2.700% notes due 2020[(a)]	$ —	$ 600
2.800% notes due 2022[(a)]	1,000	1,000
9.375% notes due 2022[(b)]	32	32
Series A notes due 2022[(b)]	3	3
8.500% notes due 2023[(b)]	70	70
8.125% notes due 2023[(b)]	131	131
3.850% notes due 2025[(a)]	900	900
4.400% notes due 2027[(a)]	1,000	1,000
6.800% notes due 2032[(a)]	550	550
6.600% notes due 2037[(a)]	750	750
5.200% notes due 2045[(a)]	500	500
Bonds:[(c)]		
2.00% bonds due 2037	200	—
2.10% bonds due 2037	200	—
2.20% bonds due 2037	200	—
Total[(b)]	5,536	5,536
Unamortized discount	(7)	(8)
Unamortized debt issuance cost	(28)	(29)
Total long-term debt	$ 5,501	$ 5,499

(a) These notes contain a make-whole provision allowing us to repay the debt at a premium to market price.
(b) In the event of a change in control, as defined in the related agreements, debt obligations totaling $236 million at December 31, 2019 may be declared immediately due and payable.
(c) Mandatory purchase dates for these bonds: April 1, 2023 for the 2.00% bonds; July 1, 2024 for the 2.10% bonds; and July 1, 2026 for the 2.20% bonds. Subsequent to the various mandatory purchase dates, we will also have the right to convert and remarket these any time up to the 2037 maturity date.

On October 3, 2019, we redeemed our $600 million 2.7% senior unsecured notes due June 2020.

The following table shows future debt payments:

(In millions)	
2020	$ —
2021	—
2022	1,035
2023	401
2024	200
Thereafter	3,900
Total long-term debt, including current portion	$ 5,536

Debt Issuance

On October 1, 2019, we closed a $600 million remarketing to investors of sub-series A bonds which are part of the $1.0 billion St. John the Baptist, State of Louisiana revenue refunding bonds originally issued and purchased in December 2017. The $600 million in proceeds from the conversion and remarketing were used to pay the purchase price of our converted 2017 bonds on the closing date. We continue to own the remaining $400 million of the revenue refunding bonds and have the right to convert and remarket them to investors at any time up to the 2037 maturity date.

18. Incentive Based Compensation

Description of stock-based compensation plans – The Marathon Oil Corporation 2019 Incentive Compensation Plan (the "2019 Plan") was approved by our stockholders in May 2019 and authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights ("SARs"), stock awards (including restricted stock and restricted stock unit awards), performance unit awards and cash awards to employees. The 2019 Plan also allows us to provide equity compensation to our non-employee directors. No more than 27.9 million shares of our common stock may be issued under the 2019 Plan. In connection with the granting of an award under the 2019 Plan, the number of shares available for issuance under the 2019 Plan will be reduced by one share for each share of our common stock in respect of which the award is granted, except that awards that by their terms do not permit settlement in shares of our common stock will not reduce the number of shares of common stock available for issuance under the 2019 Plan.

Shares subject to awards under the 2019 Plan that are forfeited, terminated or expire unexercised become available for future grants. In addition, the number of shares of our common stock reserved for issuance under the 2019 Plan will not be increased by shares tendered to satisfy the purchase price of an award, exchanged for other awards or withheld to satisfy tax withholding obligations. Shares issued as a result of awards granted under the 2019 Plan are generally funded out of common stock held in treasury, except to the extent there are insufficient treasury shares, in which case new common shares are issued.

After approval of the 2019 Plan, no new grants were or will be made from any prior plans. Any awards previously granted under any prior plans shall continue to be exercisable in accordance with their original terms and conditions.

Stock-based awards under the plans

Stock options – We grant stock options under the 2019 Plan. Our stock options represent the right to purchase shares of our common stock at its fair market value on the date of grant. In general, our stock options vest ratably over a three-year period and have a maximum term of ten years from the date they are granted.

SARs – At December 31, 2019, there are no SARs outstanding.

Restricted stock – We grant restricted stock under the 2019 Plan. The restricted stock awards granted to officers generally vest three years from the date of grant, contingent on the recipient's continued employment. We also grant restricted stock to certain non-officer employees based on their performance within certain guidelines and for retention purposes. The restricted stock awards to non-officers generally vest ratably over a three-year period, contingent on the recipient's continued employment. Prior to vesting, all restricted stock recipients have the right to vote such stock and receive dividends thereon. The non-vested shares of restricted stock are not transferable and are held by our transfer agent.

Stock-based performance units – We grant stock-based performance units to officers under the 2019 Plan. At the grant date, each unit represents the value of one share of our common stock. These units are settled in shares, and the number of shares of our common stock to be paid is based on the vesting percentage, which can be from zero to 200% based on performance achieved over a three-year performance period, and as determined by the Compensation Committee of the Board of Directors. The performance goals are tied to our total shareholder return ("TSR") as compared to TSR for a group of peer companies determined by the Compensation Committee of our Board of Directors. Dividend equivalents may accrue during the performance period and would be paid in cash at the end of the performance period based on the amount of dividends credited generally over the performance period on shares of our common stock that represent the value of the units granted multiplied by the vesting percentage.

Restricted stock units – We maintain an equity compensation program for our non-employee directors. All non-employee directors receive annual grants of common stock units. Any units granted prior to 2012 must be held until completion of board service, at which time the non-employee director will receive common shares. For units granted between 2012 and 2016, common shares will generally vest following completion of board service or three years from the date of grant, whichever is earlier. For awards issued in 2017 and later, directors may elect to defer settlement of their common stock units until after they cease serving on the Board. Absent such an election to defer, common shares will vest upon the earlier of three years from the date of grant or completion of board service. Under the 2019 Plan, we also grant restricted stock units to officers, which generally vest three years from the date of the grant and restricted stock units to certain non-officer employees, which generally vest ratably over a three-year period. Both awards are contingent on the recipient's continued employment. Grants of restricted stock units to these non-officer employees are generally based on their performance and for retention purposes. Common shares will be issued for these restricted stock units after vesting. Prior to vesting, recipients of restricted stock units typically receive dividend equivalent payments, but they may not vote.

Total stock-based compensation expense – Total employee stock-based compensation expense was $60 million, $53 million and $50 million in 2019, 2018 and 2017. Due to the full valuation allowance on our net federal deferred tax assets, we recognized no tax benefit during these years. Cash received upon exercise of stock option awards was $1 million and $26 million for 2019 and 2018. There was no cash received upon exercise of stock option awards 2017. There were no tax benefits realized for deductions for stock awards settled during 2019, 2018 and 2017.

Stock option awards – During 2019, 2018 and 2017 we granted stock option awards to officer employees. The weighted average grant date fair value of these awards was based on the following weighted average Black-Scholes assumptions:

	2019	2018	2017
Exercise price per share	$ 16.79	$ 14.52	$ 15.80
Expected annual dividend yield	1.2%	1.4%	1.3%
Expected life in years	5.82	6.45	6.4
Expected volatility	43%	43%	42%
Risk-free interest rate	2.5%	2.8%	2.1%
Weighted average grant date fair value of stock option awards granted	$ 6.62	$ 5.83	$ 6.07

The following is a summary of stock option award activity in 2019.

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value *(in millions)*
Outstanding at beginning of year	6,180,007	$ 24.39		
Granted	648,526	$ 16.79		
Exercised	(84,804)	$ 8.17		
Canceled	(1,083,998)	$ 25.45		
Outstanding at end of year	5,659,731	$ 23.55	5 years	$ 3
Exercisable at end of year	4,323,312	$ 25.96	4 years	$ 3
Expected to vest	1,319,850	$ 15.76	8 years	$ —

The intrinsic value of stock option awards exercised during 2018 was $13 million while it was immaterial during 2019 and 2017.

As of December 31, 2019, unrecognized compensation cost related to stock option awards was $5 million, which is expected to be recognized over a weighted average period of 1 year.

Restricted stock awards and restricted stock units – The following is a summary of restricted stock and restricted stock unit award activity in 2019.

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	8,504,946	$ 14.04
Granted	4,113,190	$ 16.65
Vested and Exercised	(3,813,221)	$ 12.64
Canceled	(1,630,529)	$ 15.78
Unvested at end of year	7,174,386	$ 15.88

The vesting date fair value of restricted stock awards which vested during 2019, 2018 and 2017 was $48 million, $48 million and $39 million. The weighted average grant date fair value of restricted stock awards was $15.88, $14.04 and $14.24 for awards unvested at December 31, 2019, 2018 and 2017.

As of December 31, 2019 there was $65 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of 1 year.

Stock-based performance unit awards – During 2019, 2018 and 2017 we granted 656,636, 754,140 and 563,631 stock-based performance unit awards to officers. At December 31, 2019, there were 1,282,296 units outstanding. Total stock-based performance unit awards expense was $7 million in 2019, $13 million in 2018 and $8 million in 2017.

The key assumptions used in the Monte Carlo simulation to determine the fair value of stock-based performance units granted in 2019, 2018 and 2017 were:

	2019[(a)]	2018	2017[(b)]
Valuation date stock price	$ 16.79	$ 13.69	$ 13.58
Expected annual dividend yield	1.2%	1.5%	N/A
Expected volatility	43%	41%	N/A
Risk-free interest rate	2.5%	1.5%	N/A
Fair value of stock-based performance units outstanding	$ 20.66	$ 17.29	$ 14.18

(a) Represents key assumptions at grant date, as 2019 performance unit awards are settled in stock.
(b) N/A as these stock-based performance unit awards vested as of December 31, 2019 and as such the value is based on the final payout.

19. Defined Benefit Postretirement Plans and Defined Contribution Plan

We have noncontributory defined benefit pension plans covering substantially all domestic employees. Benefits under these plans are based on plan provisions specific to each plan.

We also had a noncontributory defined benefit pension plan covering eligible U.K. employees that was transferred to the buyer in connection with the sale of our U.K. business during 2019. See Note 5 for further information on this disposition. During the year ended December 31, 2019, we reclassified $20 million from accumulated other comprehensive income to pension assets upon remeasurement of the plan.

We also have plans for other postretirement benefits covering our U.S. employees. Health care benefits are provided up to age 65 through comprehensive hospital, surgical and major medical benefit provisions subject to various cost-sharing features. Post-age 65 health care benefits are provided to certain U.S. employees on a defined contribution basis. Life insurance benefits are provided to certain retiree beneficiaries. These other postretirement benefits are not funded in advance. Employees hired after 2016 are not eligible for any postretirement health care or life insurance benefits.

Obligations and funded status – The following summarizes the obligations and funded status for our defined benefit pension and other postretirement plans.

	Pension Benefits				Other Benefits	
	2019		2018		2019	2018
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	U.S.
Accumulated benefit obligation	$ 343	$ —	$ 320	$ 511	$ 89	$ 96
Change in pension benefit obligations:						
Beginning balance	$ 326	$ 511	$ 384	$ 599	$ 96	$ 221
Service cost	19	—	18	—	1	2
Interest cost	12	8	12	14	3	7
Plan amendment	—	—	—	3	—	(99)
Divestiture[(a)]	—	(549)	—	—	—	—
Actuarial loss (gain)	48	36	(20)	(38)	9	(15)
Foreign currency exchange rate changes	—	6	—	(29)	—	—
Settlements paid	(45)	—	(62)	(23)	—	—
Benefits paid	(6)	(12)	(6)	(15)	(20)	(20)
Ending balance	$ 354	$ —	$ 326	$ 511	$ 89	$ 96
Change in fair value of plan assets:						
Beginning balance	$ 203	$ 594	$ 216	$ 670	$ —	$ —
Actual return on plan assets	44	68	(6)	(21)	—	—
Employer contributions	40	8	61	17	20	20
Foreign currency exchange rate changes	—	8	—	(34)	—	—
Divestiture[(a)]	—	(666)	—	—	—	—
Settlements paid	(45)	—	(62)	(23)	—	—
Benefits paid	(6)	(12)	(6)	(15)	(20)	(20)
Ending balance	$ 236	$ —	$ 203	$ 594	$ —	$ —
Funded status of plans at December 31	$ (118)	$ —	$ (123)	$ 83	$ (89)	$ (96)
Amounts recognized in the consolidated balance sheets:						
Noncurrent assets	$ —	$ —	$ —	$ 83	$ —	$ —
Current liabilities	(6)	—	(5)	—	(18)	(19)
Noncurrent liabilities	(112)	—	(118)	—	(71)	(77)
Accrued benefit cost	$ (118)	$ —	$ (123)	$ 83	$ (89)	$ (96)
Pretax amounts in accumulated other comprehensive loss:						
Net loss	$ 85	$ —	$ 90	$ 59	$ 23	$ 14
Prior service cost	(29)	—	(36)	5	(129)	(147)

(a) Refer to Note 5 for further information on the sale of our U.K. business.

Components of net periodic benefit cost from continuing operations and other comprehensive (income) loss – The following summarizes the net periodic benefit costs and the amounts recognized as other comprehensive (income) loss for our defined benefit pension and other postretirement plans.

	Pension Benefits						Other Benefits		
	Year Ended December 31,						Year Ended December 31,		
	2019		2018		2017		2019	2018	2017
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	U.S.	U.S.
Components of net periodic benefit cost:									
Service cost	$ 19	$ —	$ 18	$ —	$ 22	$ —	$ 1	$ 2	$ 2
Interest cost	12	8	12	14	13	17	3	7	8
Expected return on plan assets	(10)	(11)	(11)	(24)	(13)	(30)	—	—	—
Amortization:									
- prior service credit	(7)	—	(10)	—	(10)	—	(19)	(8)	(7)
- actuarial loss	7	—	11	—	8	1	1	1	—
Net settlement loss[(a)]	12	—	18	3	28	4	—	—	—
Net periodic benefit cost[(b)]	$ 33	$ (3)	$ 38	$ (7)	$ 48	$ (8)	$ (14)	$ 2	$ 3
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)	$ 14	$ (21)	$ (4)	$ 8	$ 28	$ (26)	$ 9	$ (15)	$ 5
Amortization of actuarial gain (loss)	(19)	(41)	(29)	(3)	(36)	(4)	(1)	(1)	—
Prior service cost (credit)	—	—	—	3	—	—	—	(99)	—
Amortization of prior service credit (cost)	7	(6)	10	—	10	—	19	8	7
Total recognized in other comprehensive (income) loss	$ 2	$ (68)	$ (23)	$ 8	$ 2	$ (30)	$ 27	$ (107)	$ 12
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$ 35	$ (71)	$ 15	$ 1	$ 50	$ (38)	$ 13	$ (105)	$ 15

(a) Settlements are recognized as they occur, once it is probable that lump sum payments from a plan for a given year will exceed the plan's total service and interest costs for that year.
(b) Net periodic benefit cost reflects a calculated market-related value of plan assets which recognizes changes in fair value over three years.

The estimated net loss and prior service credit for our defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2020 are $9 million and $7 million. The estimated net loss and prior service credit for our other defined benefit postretirement plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2020 are $2 million and $18 million.

Plan assumptions – The following summarizes the assumptions used to determine the benefit obligations at December 31, and net periodic benefit cost for the defined benefit pension and other postretirement plans for 2019, 2018 and 2017.

	Pension Benefits					Other Benefits		
	2019	2018		2017		2019	2018	2017
(In millions)	U.S.	U.S.	Int'l	U.S.	Int'l	U.S.	U.S.	U.S.
Weighted average assumptions used to determine benefit obligation:								
Discount rate	3.13%	4.26%	2.90%	3.55%	2.50%	2.91%	4.09%	3.54%
Rate of compensation increase	4.50%	4.00%	—%	4.00%	—%	4.50%	4.00%	4.00%
Weighted average assumptions used to determine net periodic benefit cost:								
Discount rate	3.70%	3.88%	2.50%	3.86%	2.70%	4.09%	3.54%	3.98%
Expected long-term return on plan assets	6.25%	6.50%	3.70%	6.50%	4.50%	—%	—%	—%
Rate of compensation increase	4.00%	4.00%	—%	4.00%	—%	4.00%	4.00%	4.00%

Expected long-term return on plan assets – The expected long-term return on plan assets assumption for our U.S. funded plan is determined based on an asset rate-of-return modeling tool developed by a third-party investment group which utilizes underlying assumptions based on actual returns by asset category and inflation and takes into account our U.S. pension plan's asset allocation. To determine the expected long-term return on plan assets assumption for our international plans, we consider the current level of expected returns on risk-free investments (primarily government bonds), the historical levels of the risk premiums associated with the other applicable asset categories and the expectations for future returns of each asset class. The expected return for each asset category is then weighted based on the actual asset allocation to develop the overall expected long-term return on plan assets assumption.

Assumed weighted average health care cost trend rates

Employer provided subsidies for post-65 retiree health care coverage were frozen effective January 1, 2017 at January 1, 2016 established amount levels. Company contributions are funded to a Health Reimbursement Account on the retiree's behalf to subsidize the retiree's cost of obtaining health care benefits through a private exchange (the "post-65 retiree health benefits"). Therefore, a 1% change in health care cost trend rates would not have a material impact on either the service and interest cost components and the postretirement benefit obligations.

In the fourth quarter of 2018, we terminated the post-65 retiree health benefits effective as of December 31, 2020. The post-65 retiree health benefits will no longer be provided after that date. In addition, the pre-65 retiree medical coverage subsidy has been frozen as of January 1, 2019, and the ability for retirees to opt in and out of this coverage, as well as pre-65 retiree dental and vision coverage, has also been eliminated. Retirees must enroll in connection with retirement for such coverage, or they lose eligibility. These plan changes reduced our retiree medical benefit obligation by approximately $99 million at December 31, 2018.

Plan investment policies and strategies – The investment policies for our U.S. and international pension plan assets reflect the funded status of the plans and expectations regarding our future ability to make further contributions. Long-term investment goals are to: (1) manage the assets in accordance with applicable legal requirements; (2) produce investment returns which meet or exceed the rates of return achievable in the capital markets while maintaining the risk parameters set by the plan's investment committees and protecting the assets from any erosion of purchasing power; and (3) position the portfolios with a long-term risk/return orientation. Investment performance and risk is measured and monitored on an ongoing basis through quarterly investment meetings and periodic asset and liability studies.

U.S. plan – The plan's current targeted asset allocation is comprised of 55% equity securities and 45% other fixed income securities. Over time, as the plan's funded ratio (as defined by the investment policy) improves, in order to reduce volatility in returns and to better match the plan's liabilities, the allocation to equity securities will decrease while the amount allocated to fixed income securities will increase. The plan's assets are managed by a third-party investment manager.

International plan – As mentioned above, the plan covering eligible U.K. employees that was transferred to the buyer in connection with the sale of our U.K. business during 2019.

Fair value measurements – Plan assets are measured at fair value. The following provides a description of the valuation techniques employed for each major plan asset class at December 31, 2019 and 2018.

Cash and cash equivalents – Cash and cash equivalents are valued using a market approach and are considered Level 1.

Equity securities – Investments in common stock are valued using a market approach at the closing price reported in an active market and are therefore considered Level 1. Private equity investments include interests in limited partnerships which are valued based on the sum of the estimated fair values of the investments held by each partnership, determined using a combination of market, income and cost approaches, plus working capital, adjusted for liabilities, currency translation and estimated performance incentives. These private equity investments are considered Level 3. Investments in pooled funds are valued using a market approach, these various funds consist of equity with underlying investments held in U.S. and non-U.S. securities. The pooled funds are benchmarked against a relative public index and are considered Level 2.

Fixed income securities – Fixed income securities are valued using a market approach. U.S. treasury notes and exchange traded funds ("ETFs") are valued at the closing price reported in an active market and are considered Level 1. Corporate bonds, private placements, and GNMA/FNMA/FHLMC pools are valued using calculated yield curves created by models that incorporate various market factors. Primarily investments are held in U.S. and non-U.S. corporate bonds in diverse industries and are considered Level 2. Forward contracts included under government securities are traded in the over-the-counter market and occur between two parties only with no intermediary. The details of each contract such as trade size, price and maturity are tailored to each security and negotiated between the two parties, as such, these investments are considered Level 3. Other fixed income investments include zero coupon and interest rate swaps. Investments in pooled funds are valued using a market approach, and primarily have investments held in U.S. and non-U.S. publicly traded investment grade government and corporate bonds and are considered Level 2.

Other – Other investments are comprised of an unallocated annuity contract, two limited liability companies, and real estate. All are considered Level 3, as significant inputs to determine fair value are unobservable.

Commingled funds – The investment in the commingled funds are valued using the net asset value of units held as a practical expedient. The commingled funds consist of equity and fixed income portfolios with underlying investments held in U.S. and non-U.S. securities.

The following tables present the fair values of our defined benefit pension plan's assets, by level within the fair value hierarchy, as of December 31, 2019 and 2018.

	December 31, 2019			
(In millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents[(a)]	$ (7)	$ —	$ —	$ (7)
Equity securities:				
Common stock	75	—	—	75
Private equity	—	—	10	10
Pooled funds	—	—	—	—
Fixed income securities:				
Corporate	—	2	—	2
Exchange traded funds	3	—	—	3
Government	31	11	5	47
Pooled funds	—	—	—	—
Other	—	—	18	18
Total investments, at fair value	102	13	33	148
Commingled funds[(b)]	—	—	—	88
Total investments	$ 102	$ 13	$ 33	$ 236

	December 31, 2018							
(In millions)	**Level 1**		**Level 2**		**Level 3**		**Total**	
	U.S.	**Int'l**	**U.S.**	**Int'l**	**U.S.**	**Int'l**	**U.S.**	**Int'l**
Cash and cash equivalents[(a)]	$ (1)	$ 5	$ —	$ —	$ —	$ —	$ (1)	$ 5
Equity securities:								
Common stock	75	—	—	—	—	—	75	—
Private equity	—	—	—	—	14	—	14	—
Pooled funds	—	—	—	191	—	—	—	191
Fixed income securities:								
Corporate	—	—	4	—	—	—	4	—
Government	22	—	9	—	3	—	34	—
Pooled funds	—	—	—	398	—	—	—	398
Other	—	—	—	—	17	—	17	—
Total investments, at fair value	96	5	13	589	34	—	143	594
Commingled funds[(b)]	—	—	—	—	—	—	60	—
Total investments	$ 96	$ 5	$ 13	$ 589	$ 34	$ —	$ 203	$ 594

(a) The negative cash balance was due to the timing of when investment trades occur and when they settle.
(b) After the adoption of the FASB update for the fair value hierarchy, we separately report the investments for which fair value was measured using the net asset value per share as a practical expedient. Amounts presented in this table are intended to reconcile the fair value hierarchy to the pension plan assets.

The activity during the year ended December 31, 2019 and 2018, for the assets using Level 3 fair value measurements was immaterial.

Cash flows

Estimated future benefit payments – The following gross benefit payments, which were estimated based on actuarial assumptions applied at December 31, 2019 and reflect expected future services, as appropriate, are to be paid in the years indicated.

(In millions)	Pension Benefits	Other Benefits
2020	$ 39	$ 18
2021	35	10
2022	31	9
2023	29	8
2024	27	7
2025 through 2029	116	25

Contributions to defined benefit plans – We expect to make contributions to the funded pension plan of up to $28 million in 2020. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $6 million and $18 million in 2020.

Contributions to defined contribution plans – We contribute to several defined contribution plans for eligible employees. Contributions to these plans totaled $18 million, $22 million and $20 million in 2019, 2018 and 2017.

20. Reclassifications Out of Accumulated Other Comprehensive Income (Loss)

The following table presents a summary of amounts reclassified from accumulated other comprehensive income (loss):

	Year Ended December 31,		
(In millions)	2019	2018	Income Statement Line
Postretirement and postemployment plans			
Amortization of prior service credit	$ 26	$ 18	Other net periodic benefit costs
Amortization of actuarial loss	(8)	(12)	Other net periodic benefit costs
Net settlement loss, net of tax	(12)	(20)	Other net periodic benefit costs
	6	(14)	
Other			
U.K pension plan transferred to buyer [(a)(b)]	83	—	
Foreign currency translation adjustment related to sale of U.K. business[(b)]	30	—	
Income taxes related to sale of U.K. business [(b)]	(45)	—	
	68	—	Net gain on disposal of assets
Other insignificant items, net of tax	1	—	Net interest and other
Total reclassifications to expense, net of tax	$ 75	$ (14)	Net income (loss)

(a) See **Note 19** for detail on the U.K. pension plan.
(b) See **Note 5** for detail on the U.K. disposition.

21. Supplemental Cash Flow Information

	Year Ended December 31,		
(In millions)	2019	2018	2017
Included in operating activities:			
Interest paid, net of amounts capitalized	$ 269	$ 270	$ 379
Income taxes paid to taxing authorities, net of refunds received[(a)]	73	287	391
Noncash investing activities, related to continuing operations:			
Increase (decrease) in asset retirement costs	$ 80	$ (183)	$ (202)
Asset retirement obligations assumed by buyer[(b)]	1,082	82	14
Notes receivable for disposition of assets	—	—	748

(a) 2019, 2018 and 2017 includes $90 million, $37 million and $1 million, related to tax refunds. 2017 included a payment of $108 million made to the U.K. tax authorities to preserve our appeal rights, see **Note 25** for additional discussion.

(b) In 2019, our dispositions include the sale of the Droshky field (Gulf of Mexico), the sale of our non-operated interest in the Atrush block in Kurdistan and the sale of our U.K. business. See **Note 5** for further detail on dispositions.

Other noncash investing activities include accrued capital expenditures as of December 31, 2019, 2018 and 2017 of $288 million, $250 million and $329 million.

22. Other Items

Net interest and other

	Year Ended December 31,		
(In millions)	2019	2018	2017
Interest:			
Interest income	$ 25	$ 32	$ 34
Interest expense	(280)	(280)	(380)
Income on interest rate swaps	—	—	53
Interest capitalized	—	—	3
Total interest	(255)	(248)	(290)
Other:			
Net foreign currency gain (loss)	4	9	8
Other	7	13	12
Total other	11	22	20
Net interest and other	$ (244)	$ (226)	$ (270)

Foreign currency – Aggregate foreign currency gains (losses) were included in the consolidated statements of income as follows:

	Year Ended December 31,		
(In millions)	2019	2018	2017
Net interest and other	$ 4	$ 9	$ 8
Provision for income taxes	2	10	57
Aggregate foreign currency gains	$ 6	$ 19	$ 65

23. Equity Method Investments

During 2019, 2018 and 2017 our equity method investees were considered related parties and included:

- EGHoldings, in which we have a 60% noncontrolling interest. EGHoldings is engaged in LNG production activity.
- Alba Plant LLC, in which we have a 52% noncontrolling interest. Alba Plant LLC processes LPG.
- AMPCO, in which we have a 45% noncontrolling interest. AMPCO is engaged in methanol production activity.

Our equity method investments are summarized in the following table:

(In millions)	**Ownership as of December 31, 2019**	**December 31, 2019**	**December 31, 2018**
EGHoldings	60%	$ 310	$ 402
Alba Plant LLC	52%	163	167
AMPCO	45%	190	176
Total		$ 663	$ 745

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $105 million in 2019, $270 million in 2018 and $276 million in 2017.

Summarized financial information for equity method investees is as follows:

(In millions)	**2019**	**2018**	**2017**
Income data – year:			
Revenues and other income	$ 832	$ 1,269	$ 1,294
Income from operations	250	588	631
Net income	187	459	508
Balance sheet data – December 31:			
Current assets	$ 455	$ 559	
Noncurrent assets	1,049	931	
Current liabilities	284	253	
Noncurrent liabilities	183	87	

Revenues from related parties were $42 million, $48 million and $60 million in 2019, 2018 and 2017, respectively, with the majority related to EGHoldings in all years. We had no purchases from related parties during both 2019 and 2018, and $132 million in 2017, with the majority related to Alba Plant LLC.

Current receivables from related parties at December 31, 2019 and 2018 were $28 million and $25 million, with the majority related to EGHoldings and Alba Plant LLC for 2019 and EGHoldings in 2018. Payables to related parties were $11 million and $15 million at December 31, 2019 and 2018, respectively, with the majority related to Alba Plant LLC.

24. Stockholders' Equity

On July 31, 2019, the Board of Directors authorized an extension of the share repurchase program, which increased the remaining share repurchase authorization to $1.5 billion. During 2019, we acquired approximately 24 million of common shares at a cost of $345 million, which were held as treasury stock. During 2018, we acquired 36 million of common shares at a cost of $700 million under the same program. As of December 31, 2019 the total remaining share repurchase authorization was $1.4 billion. Purchases under the program are made at our discretion and may be in either open market transactions, including block purchases, or in privately negotiated transactions using cash on hand, cash generated from operations or proceeds from potential asset sales. This program may be changed based upon our financial condition or changes in market conditions and is subject to termination prior to completion. The repurchase program does not include specific price targets or timetables.

25. Commitments and Contingencies

Following the sale of our U.K. business to RockRose, we continued to hold outstanding surety bonds which guaranteed our decommissioning liabilities related to the Marathon Oil U.K. LLC assets. We issued these surety bonds in November 2018 with a notional value of approximately £92 million and an expiration date of December 31, 2019. RockRose was contractually required to post a replacement security to cover 2020 by no later than December 1, 2019. During the third quarter of 2019, we recorded a $6 million liability and corresponding expense related to the estimated fair value of our exposure to surety bonds. In November 2019, RockRose posted replacement security and accordingly, we reversed the aforementioned $6 million. See Note 5 for discussion of the U.K. sale in further detail.

In the second quarter of 2019, Marathon E.G. Production Limited ("MEGPL"), a consolidated and wholly-owned subsidiary, signed a series of agreements to process third-party Alen Unit gas through existing infrastructure located in Punta Europa, E.G. MEGPL is a signatory to the agreements related to our equity method investee, Alba Plant LLC. These agreements contain clauses that cause MEGPL to indemnify the owners of the Alen Unit against actions or inaction by Alba Plant LLC. Pursuant to these agreements, MEGPL agreed to indemnify third party property or events, including environmental assessments, injury to Alba Plant LLC's personnel, and damage to or loss of Alba Plant LLC's automobiles. At this time, we cannot reasonably estimate this obligation as we do not have any history of prior indemnification claims, as completion of the plant modifications is not expected to finish until 2021, and as such, we do not have any history of environmental discharge or contamination. Therefore, we have not recorded a liability with respect to these indemnification clauses since the amount of potential future payments under such guarantees is not determinable.

We are routinely undergoing examination of our U.S. federal income tax returns by the IRS. With the closure of the 2010-2011 IRS Audit referenced in Note 8, these audits have been completed through the 2016 tax year with the exception of the following item. During the third quarter of 2017, we received a partnership adjustment notification related to the 2010 and 2011 tax years, for which we filed a Tax Court Petition in the fourth quarter of 2017. During the third quarter of 2019, we received the court decision which ruled in our favor for all material items. At December 31, 2019, all issues have been effectively settled related to the partnership audit.

Various groups, including the State of North Dakota and three Indian tribes represented by the Bureau of Indian Affairs, have been involved in a dispute regarding the ownership of certain lands underlying the Missouri River and Little Missouri River. As a result, as of December 31, 2019, we have recorded a $93 million liability in suspended royalty and working interest revenue, including interest, and have recorded a long-term receivable of $20 million for capital and expenses.

We are a defendant in a number of legal and administrative proceedings arising in the ordinary course of business including, but not limited to, royalty claims, contract claims, tax disputes and environmental claims. While the ultimate outcome and impact to us cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. Certain of these matters are discussed below.

Environmental matters – We have incurred and will continue to incur capital, operating and maintenance, and remediation expenditures as a result of environmental laws and regulations. If these expenditures, as with all costs, are not ultimately offset by the prices we receive for our products and services, our operating results will be adversely affected. We believe that substantially all of our competitors must comply with similar environmental laws and regulations. However, the specific impact on each competitor may vary depending on a number of factors, including the age and location of its operating facilities, marketing areas and production processes. These laws generally provide for control of pollutants released into the environment and require responsible parties to undertake remediation of hazardous waste disposal sites. Penalties may be imposed for noncompliance.

At December 31, 2019 and 2018, accrued liabilities for remediation were not material. It is not presently possible to estimate the ultimate amount of all remediation costs that might be incurred or the penalties that may be imposed.

Guarantees – Over the years, we have sold various assets in the normal course of our business. Certain of the related agreements contain performance and general guarantees, including guarantees regarding inaccuracies in representations, warranties, covenants and agreements, and environmental and general indemnifications that require us to perform upon the occurrence of a triggering event or condition. These guarantees and indemnifications are part of the normal course of selling assets. We are typically not able to calculate the maximum potential amount of future payments that could be made under such contractual provisions because of the variability inherent in the guarantees and indemnities. Most often, the nature of the guarantees and indemnities is such that there is no appropriate method for quantifying the exposure because the underlying triggering event has little or no past experience upon which a reasonable prediction of the outcome can be based.

Contract commitments – At December 31, 2019 and 2018, contractual commitments to acquire property, plant and equipment totaled $41 million and $57 million.

In connection with the sale of our operated producing properties in the greater Ewing Bank area and non-operated producing interests in the Petronius and Neptune fields in the Gulf of Mexico, we retained an overriding royalty interest in the properties. As part of the sale agreement, proceeds associated with the production of our override were $46 million as of December 31, 2019, and are dedicated solely to the satisfaction of the corresponding future abandonment obligations of the properties. The term of our override ends once sales proceeds equal $70 million.

Select Quarterly Financial Data (Unaudited)

(In millions, except per share data)	2019 1st Qtr.	2019 2nd Qtr.	2019 3rd Qtr.	2019 4th Qtr.	2018 1st Qtr.	2018 2nd Qtr.	2018 3rd Qtr.	2018 4th Qtr.
Revenues from contracts with customers	$ 1,200	$ 1,381	$ 1,249	$ 1,233	$ 1,537	$ 1,447	$ 1,538	$ 1,380
Income (loss) before income taxes	27 [a]	193	175	(3) [a]	524	140	357	406 [b]
Net income (loss)	$ 174	$ 161	$ 165	$ (20)	$ 356	$ 96	$ 254	$ 390
Income (loss) per basic and diluted share:								
Net income (loss)	$ 0.21	$ 0.20	$ 0.21	$ (0.03)	$ 0.42	$ 0.11	$ 0.30	$ 0.47
Dividends paid per share	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05

[a] The first and fourth quarter of 2019 includes mark-to-market loss on commodity derivatives of $113 million and $55 million.

[b] The fourth quarter of 2018 includes a mark-to-market gain on commodity derivatives of $336 million and unproved property impairments and exploratory dry well costs of $49 million in the fourth quarter of 2018. (See Item 8. Financial Statements and Supplementary Data - **Note 11** to the consolidated financial statements). Additionally, the first quarter of 2018 includes a gain on sale of our Libya subsidiary of $255 million. (See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements).

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

The supplementary information is disclosed by the following geographic areas: the U.S.; E.G.; Libya; and Other International ("Other Int'l"), which includes the U.K., Gabon and the Kurdistan Region of Iraq. For further details on our dispositions that affect the information included in this supplemental information, see **Note 5**.

Preparation of Reserve Estimates

All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X. Crude oil and condensate, NGLs, natural gas and our historical synthetic crude oil reserve estimates are reviewed and approved by our Corporate Reserves Group ("CRG"), which includes our Director of Corporate Reserves and his staff of Reserve Coordinators. Crude oil and condensate, NGLs and natural gas reserve estimates are developed or reviewed by Qualified Reserves Estimators ("QREs"). QREs are petro-technical professionals located throughout our organization who meet the qualifications we have established for employees engaged in estimating reserves and resources. QREs have the education, experience, and training necessary to estimate reserves and resources in a manner consistent with all external reserve estimation regulations and internal resource estimation directives and practices. QREs generally hold at least a Bachelor of Science degree in the appropriate technical field, have a minimum of five years of industry experience with at least three years in reserve estimation and have completed our QRE training course. All reserves changes (including proved) must be approved by our CRG. Additionally, any change to proved reserve estimates in excess of 5 mmboe on a total field basis, within a single month, must be approved by the Director of Corporate Reserves.

The Director of Corporate Reserves, who reports to our Chief Financial Officer, has a Bachelor of Science degree in petroleum engineering and is a registered Professional Engineer in the State of New Mexico. In his 33 years with Marathon Oil, he has held numerous engineering and management positions, including managing reservoir engineering and geoscience for our Eagle Ford development in South Texas. He is a 25 year member of the Society of Petroleum Engineers ("SPE").

Technologies used in proved reserves estimation includes statistical analysis of production performance, decline curve analysis, pressure and rate transient analysis, pressure gradient analysis, reservoir simulation and volumetric analysis. The observed statistical nature of production performance coupled with highly certain reservoir continuity or quality within the reliable technology areas and sufficient proved developed locations establish the reasonable certainty criteria required for booking proved reserves.

Audits of Estimates

We have established a robust series of internal controls, policies and processes intended to ensure the quality and accuracy of our internal reserve estimates. We also engage third-party consultants to audit our estimates of proved reserves. Our policy requires that audits are provided for fields that comprise at least 80% of our total proved reserves over a rolling four-year period, adjusted for dispositions. We conduct our audits on a one-year in arrears basis and accordingly, our third-party consultants have not yet performed any audits of our reserve estimates for the year-ended December 31, 2019. In calculating our proved reserve audit coverage percentage, we only include the most recent year a field was audited within the rolling four-year period. To illustrate, our third-party proved reserve audits conducted during 2019 were for reserve estimates as of December 31, 2018 and covered reserves in Oklahoma (284 mmboe) and Eagle Ford (386 mmboe). The reserve audits conducted during 2018 were for reserve estimates as of December 31, 2017 and included reserves in Bakken (321 mmboe), which is reflected net of 2018 production in calculating our audit coverage as of December 31, 2019. The reserve audits conducted during 2017 were for reserve estimates as of December 31, 2016 and included reserves in Equatorial Guinea (151 mmboe), which is reflected net of 2017 and 2018 production in calculating our audit coverage as of December 31, 2019. On this basis, our third-party reserve audits covered 92% of our total proved reserves, excluding dispositions. An audit tolerance at a field level of +/- 10% to our internal estimates has been established. All audits conducted during this period fell within the established tolerance.

For the reserve estimates as of December 31, 2016, Netherland, Sewell & Associates, Inc. ("NSAI") prepared a reserves certification for the Alba field in E.G. The NSAI summary report is filed as an exhibit to this Annual Report on Form 10-K. Members of the NSAI team have multiple years of industry experience, having worked for large, international oil and gas companies before joining NSAI. NSAI's technical team members meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE. The senior technical advisor has over 15 years of practical experience in petroleum engineering and the estimation and evaluation of reserves and is a registered Professional Engineer in the State of Texas. The second team member has over 13 years of practical experience in petroleum geosciences and is a licensed Professional Geoscientist in the State of Texas.

Ryder Scott Company performed audits for reserve estimates of our fields as of December 31, 2018 and 2017. Their summary reports are filed as exhibits to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 37 years of industry experience, having worked for a major financial advisory services group before joining Ryder Scott. He is a 25 year member of SPE and is a registered Professional Engineer in the State of Texas.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves

The estimation of net recoverable quantities of crude oil and condensate, NGLs, natural gas and our historical synthetic crude oil is a highly technical process which is based upon several underlying assumptions that are subject to change. Proved reserves are determined using "SEC Pricing", calculated as an unweighted arithmetic average of the first-day-of-the-month closing price for each month. As discussed in **Item 1A. Risk Factors** and **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Estimates**, commodity prices are volatile which can have an impact on proved reserves. If crude oil prices in the future average below prices used to determine proved reserves at December 31, 2019, it could have an adverse effect on our estimates of proved reserve volumes and the value of our business. Future reserve revisions could also result from changes in capital funding, drilling plans and governmental regulation, among other things. It is difficult to estimate the magnitude of any potential price change and the effect on proved reserves, due to numerous factors (including future crude oil price and performance revisions).

The table below provides the 2019 SEC pricing for certain benchmark prices:

		2019 SEC Pricing
WTI Crude oil *(per bbl)*	$	55.69
Henry Hub natural gas *(per mmbtu)*	$	2.58
Brent crude oil *(per bbl)*	$	63.15
Mont Belvieu NGLs *(per bbl)*	$	18.41

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves

(mmbbl)	U.S.	E.G.[(a)]	Libya[(b)]	Other Int'l[(c)]	Cont Ops[(d)]
Crude oil and condensate					
Proved developed and undeveloped reserves:					
Beginning of year - 2017	563	45	172	22	802
Revisions of previous estimates	9	(2)	—	8	15
Purchases of reserves in place	18	—	—	—	18
Extensions, discoveries and other additions	30	4	—	—	34
Production	(49)	(8)	(7)	(4)	(68)
Sales of reserves in place	(1)	—	—	—	(1)
End of year - 2017	570	39	165	26	800
Revisions of previous estimates	49	3	—	3	55
Extensions, discoveries and other additions	42	—	—	2	44
Production	(63)	(6)	(3)	(5)	(77)
Sales of reserves in place	(3)	—	(162)	(1)	(166)
End of year - 2018	595	36	—	25	656
Revisions of previous estimates	34	3	—	—	37
Purchases of reserves in place	9	—	—	—	9
Extensions, discoveries and other additions	53	—	—	—	53
Production	(69)	(6)	—	(2)	(77)
Sales of reserves in place	(3)	—	—	(23)	(26)
End of year - 2019	619	33	—	—	652
Proved developed reserves:					
Beginning of year - 2017	238	45	172	13	468
End of year - 2017	263	39	165	17	484
End of year - 2018	287	36	—	22	345
End of year - 2019	304	30	—	—	334
Proved undeveloped reserves:					
Beginning of year - 2017	325	—	—	9	334
End of year - 2017	307	—	—	9	316
End of year - 2018	308	—	—	3	311
End of year - 2019	315	3	—	—	318

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	E.G.[(a)]	Libya[(b)]	Other Int'l[(c)]	Cont Ops[(d)]
Natural gas liquids					
Proved developed and undeveloped reserves:					
Beginning of year - 2017	170	24	—	—	194
Revisions of previous estimates	37	3	—	—	40
Purchases of reserves in place	5	—	—	—	5
Extensions, discoveries and other additions	34	2	—	—	36
Production	(16)	(4)	—	—	(20)
Sales of reserves in place	(1)	—	—	—	(1)
End of year - 2017	229	25	—	—	254
Revisions of previous estimates	(9)	1	—	—	(8)
Extensions, discoveries and other additions	25	—	—	—	25
Production	(20)	(4)	—	—	(24)
Sales of reserves in place	(1)	—	—	—	(1)
End of year - 2018	224	22	—	—	246
Revisions of previous estimates	(21)	2	—	—	(19)
Purchases of reserves in place	5	—	—	—	5
Extensions, discoveries and other additions	19	—	—	—	19
Production	(22)	(3)	—	—	(25)
Sales of reserves in place	(1)	—	—	—	(1)
End of year - 2019	204	21	—	—	225
Proved developed reserves:					
Beginning of year - 2017	78	24	—	—	102
End of year - 2017	118	25	—	—	143
End of year - 2018	119	22	—	—	141
End of year - 2019	122	19	—	—	141
Proved undeveloped reserves:					
Beginning of year - 2017	92	—	—	—	92
End of year - 2017	111	—	—	—	111
End of year - 2018	105	—	—	—	105
End of year - 2019	82	2	—	—	84

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(bcf)	U.S.	E.G.[(a)]	Libya[(b)]	Other Int'l[(c)]	Cont Ops[(d)]
Natural gas					
Proved developed and undeveloped reserves:					
Beginning of year - 2017	1,288	943	205	10	2,446
Revisions of previous estimates	(33)	(18)	—	4	(47)
Purchases of reserves in place	36	—	—	—	36
Extensions, discoveries and other additions	204	76	—	—	280
Production[(e)]	(127)	(168)	(1)	(6)	(302)
Sales of reserves in place	(44)	—	—	—	(44)
End of year - 2017	1,324	833	204	8	2,369
Revisions of previous estimates	188	35	—	4	227
Extensions, discoveries and other additions	198	—	—	—	198
Production[(e)]	(156)	(153)	(1)	(5)	(315)
Sales of reserves in place	(1)	—	(203)	—	(204)
End of year - 2018	1,553	715	—	7	2,275
Revisions of previous estimates	(223)	108	—	—	(115)
Purchases of reserves in place	28	—	—	—	28
Extensions, discoveries and other additions	118	—	—	—	118
Production[(e)]	(160)	(133)	—	(3)	(296)
Sales of reserves in place	(38)	—	—	(4)	(42)
End of year - 2019	1,278	690	—	—	1,968
Proved developed reserves:					
Beginning of year - 2017	648	943	95	5	1,691
End of year - 2017	726	833	94	2	1,655
End of year - 2018	869	715	—	7	1,591
End of year - 2019	825	649	—	—	1,474
Proved undeveloped reserves:					
Beginning of year - 2017	640	—	110	5	755
End of year - 2017	598	—	110	6	714
End of year - 2018	684	—	—	—	684
End of year - 2019	453	41	—	—	494

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	**Disc Ops**
Synthetic crude oil	
Proved developed and undeveloped reserves:	
Beginning of year - 2017	692
Production	(7)
Sales of reserves in place	(685)
End of year - 2017	—
Proved developed reserves:	
Beginning of year - 2017	692
End of year - 2017	—
Proved undeveloped reserves:	
Beginning of year - 2017	—
End of year - 2017	—

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmboe)	U.S.	E.G.[(a)]	Libya[(b)]	Other Int'l[(c)]	Cont Ops[(d)]	Disc Ops	Total
Total Proved Reserves							
Proved developed and undeveloped reserves:							
Beginning of year - 2017	948	226	206	24	1,404	692	2,096
Revisions of previous estimates	42	(1)	—	8	49	—	49
Purchases of reserves in place	28	—	—	—	28	—	28
Extensions, discoveries and other additions	98	18	—	—	116	—	116
Production[(e)]	(86)	(40)	(7)	(5)	(138)	(7)	(145)
Sales of reserves in place	(10)	—	—	—	(10)	(685)	(695)
End of year - 2017	1,020	203	199	27	1,449	—	1,449
Revisions of previous estimates	71	8	—	5	84	—	84
Extensions, discoveries and other additions	100	—	—	2	102	—	102
Production[(e)]	(109)	(35)	(3)	(6)	(153)	—	(153)
Sales of reserves in place	(4)	—	(196)	(1)	(201)	—	(201)
End of year - 2018	1,078	176	—	27	1,281	—	1,281
Revisions of previous estimates	(23)	24	—	—	1	—	1
Purchases of reserves in place	18	—	—	—	18	—	18
Extensions, discoveries and other additions	91	—	—	—	91	—	91
Production[(e)]	(117)	(31)	—	(3)	(151)	—	(151)
Sales of reserves in place	(11)	—	—	(24)	(35)	—	(35)
End of year - 2019	1,036	169	—	—	1,205	—	1,205
Proved developed reserves:							
Beginning of year - 2017	424	226	188	14	852	692	1,544
End of year - 2017	502	203	181	17	903	—	903
End of year - 2018	552	176	—	24	752	—	752
End of year - 2019	563	158	—	—	721	—	721
Proved undeveloped reserves:							
Beginning of year - 2017	524	—	18	10	552	—	552
End of year - 2017	518	—	18	10	546	—	546
End of year - 2018	526	—	—	3	529	—	529
End of year - 2019	473	11	—	—	484	—	484

(a) Consists of estimated reserves from properties governed by production sharing contracts.

(b) In 2018, we closed on the sale of our subsidiary, Marathon Oil Libya Limited.

(c) In 2019, we closed on the sale of our U.K. business and our non-operated interested in the Atrush block of Kurdistan. These volumes are reflected in Other Int'l in the tables above for the periods presented.

(d) Continuing operations ("Cont Ops") excludes the sale of our Canada business which was reflected as discontinued operations ("Disc Ops") in 2017. Proved reserves in our Canada business consisted entirely of synthetic crude oil.

(e) Excludes the resale of purchased natural gas used in reservoir management.

2019 proved reserves decreased by 76 mmboe primarily due to the following:

- *Revisions of previous estimates:* Increased by 1 mmboe as referenced below:

  Increases:
  - 20 mmboe associated with wells to sales that were additions to the plan
  - 11 mmboe associated with planned compression in E.G.
  - 11 mmboe due to technical revisions in E.G.

  Decreases:
  - 24 mmboe due to reduced commodity pricing
  - 12 mmboe due to technical revisions in the U.S. resource plays
  - 5 mmboe due to changes in the 5-year plan in the U.S. resource plays
- *Purchases of reserves in place:* Increased by 18 mmboe due to the acquisition in the Eagle Ford.
- *Extensions, discoveries, and other additions:* Increased by 91 mmboe in the U.S. resource plays as referenced below:

  Increases:
  - 53 mmboe associated with the expansion of proved areas
  - 38 mmboe associated with wells to sales from unproved categories
- *Production:* Decreased by 151 mmboe.
- *Sales of reserves in place:* Decreased by 35 mmboe as referenced below:

  Decreases:
  - 19 mmboe associated with the sale of assets in the U.K.
  - 11 mmboe associated with divestitures of certain U.S. assets
  - 5 mmboe associated with the sale of the Atrush block in Kurdistan

2018 proved reserves decreased by 168 mmboe primarily due to the following:

- *Revisions of previous estimates:* Increased by 84 mmboe as referenced below:

  Increases:
  - 108 mmboe associated with the acceleration of higher economic wells in the U.S. resource plays into the 5-year plan
  - 15 mmboe associated with wells to sales that were additions to the plan

  Decreases:
  - 39 mmboe due to technical revisions across the business
- *Extensions, discoveries, and other additions:* Increased by 102 mmboe primarily in the U.S. resource plays as referenced below:

  Increases:
  - 69 mmboe associated with the expansion of proved areas
  - 33 mmboe associated with wells to sales from unproved categories
- *Production:* Decreased by 153 mmboe.
- *Sales of reserves in place:* Decreased by 201 mmboe as referenced below:

  Decreases:
  - 196 mmboe associated with the sale of our subsidiary in Libya
  - 4 mmboe associated with divestitures of certain conventional assets in New Mexico and Michigan
  - 1 mmboe associated with the sale of the Sarsang block in Kurdistan

2017 proved reserves decreased by 647 mmboe primarily due to the following:

- *Revisions of previous estimates:* Increased by 49 mmboe as referenced below:

  Increases:
  - 44 mmboe due to the acceleration of higher economic wells in the Bakken into the 5-year plan
  - The remainder being due to revisions across the business
- *Extensions, discoveries, and other additions:* Increased by 116 mmboe primarily due to an increase of 97 mmboe associated with the expansion of proved areas and wells to sales from unproved categories in Oklahoma.
- *Purchases of reserves in place:* Increased by 28 mmboe from acquisitions of assets in the Northern Delaware Basin in New Mexico.
- *Production:* Decreased by 145 mmboe.

- *Sales of reserves in place:* Decreased by 695 mmboe as referenced below:

  Increases:

  - 685 mmboe associated with the sale of our Canadian business
  - 10 mmboe associated with divestitures of certain conventional assets in Oklahoma and Colorado. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for information regarding these dispositions.

Changes in Proved Undeveloped Reserves

The following table shows changes in proved undeveloped reserves for 2019:

(mmboe)	
Beginning of year	529
Revisions of previous estimates	18
Purchases of reserves in place	13
Extensions, discoveries, and other additions	68
Dispositions	(5)
Transfers to proved developed	(139)
End of year	484

Revisions of prior estimates: Increased by 18 mmboe as referenced below:

Increases:

- 16 mmboe associated with in-year drill schedule changes
- 11 mmboe associated with planned compression in E.G.

Decreases:

- 5 mmboe due to changes in the 5-year plan in the U.S. resource plays
- 4 mmboe due to technical revisions

Extensions, discoveries and other additions: Increased by 68 mmboe associated with expansion of proved areas in the U.S. resource plays as referenced below:

Increases:

- 28 mmboe in Oklahoma
- 25 mmboe in Permian
- 15 mmboe in Bakken

Transfers to proved developed: 139 mmboe of PUD reserves were converted to proved developed status during 2019, primarily from assets in our U.S. resource plays. This 2019 transfer equates to a 26% PUD conversion rate and a 5-year average annual PUD conversion rate during the 2015-2019 period of 20%. All proved undeveloped reserve drilling locations are scheduled to be producing within five years of the initial booking date.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Costs Incurred & Future Costs to Develop

Costs incurred in 2019, 2018 and 2017 relating to the development of proved undeveloped reserves were $1,261 million, $1,082 million and $842 million.

The following table shows future development costs estimated to be required for the development of proved undeveloped reserves for future years.

(In millions)		Future Development Costs
2020	$	1,464
2021		1,568
2022		1,562
2023		1,456
2024		913

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

(In millions)		U.S.		E.G.		Other Int'l		Total
Year Ended December 31, 2019								
Capitalized Costs:								
Proved properties	$	29,250	$	2,042	$	—	$	31,292
Unproved properties		2,880		12		—		2,892
Total		32,130		2,054		—		34,184
Accumulated depreciation, depletion and amortization:								
Proved properties		15,435		1,568		—		17,003
Unproved properties[(a)]		357		(7)		—		350
Total		15,792		1,561		—		17,353
Net capitalized costs	$	16,338	$	493	$	—	$	16,831
Year Ended December 31, 2018								
Capitalized Costs:								
Proved properties	$	27,983	$	2,041	$	4,828	$	34,852
Unproved properties		2,977		11		—		2,988
Total		30,960		2,052		4,828		37,840
Accumulated depreciation, depletion and amortization:								
Proved properties		14,742		1,471		4,706		20,919
Unproved properties[(a)]		299		(7)		—		292
Total		15,041		1,464		4,706		21,211
Net capitalized costs	$	15,919	$	588	$	122	$	16,629

(a) Includes unproved property impairments (see **Note 11**).

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Costs Incurred for Property Acquisition, Exploration and Development [(a)]

(In millions)	U.S.	E.G.	Libya	Other Int'l	Cont Ops	Disc Ops	Total
December 31, 2019							
Property acquisition:							
Proved	$ 93	$ —	$ —	$ —	$ 93	$ —	$ 93
Unproved	282	—	—	—	282	—	282
Exploration	862	—	—	—	862	—	862
Development	1,675	1	—	23	1,699	—	1,699
Total	$ 2,912	$ 1	$ —	$ 23	$ 2,936	$ —	$ 2,936
December 31, 2018							
Property acquisition:							
Proved	$ 211	$ —	$ —	$ 11	$ 222	$ —	$ 222
Unproved	144	—	—	—	144	—	144
Exploration	929	1	—	(9)	921	—	921
Development	1,332	(2)	—	(126) [(b)]	1,204	—	1,204
Total	$ 2,616	$ (1)	$ —	$ (124)	$ 2,491	$ —	$ 2,491
December 31, 2017							
Property acquisition:							
Proved	$ 191	$ 1	$ —	$ —	$ 192	$ —	$ 192
Unproved	1,746	—	—	1	1,747	—	1,747
Exploration	882	1	—	40	923	—	923
Development	1,122	5	10	(144) [(b)]	993	6	999
Total	$ 3,941	$ 7	$ 10	$ (103)	$ 3,855	$ 6	$ 3,861

(a) Includes costs incurred whether capitalized or expensed.

(b) Includes revisions to asset retirement costs primarily due to changes in U.K. estimated costs as well as timing of abandonment activities.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

	U.S.	E.G.	Libya	Other Int'l	Cont Ops	Disc Ops	Total
Year Ended December 31, 2019							
Revenues and other income:							
Sales	$ 4,472	$ 307	$ —	$ 140	$ 4,919	$ —	$ 4,919
Other income[a]	46	—	—	3	49	—	49
Total revenues and other income	4,518	307	—	143	4,968	—	4,968
Expenses:							
Production costs	(1,384)	(73)	—	(71)	(1,528)	—	(1,528)
Exploration expenses[b]	(149)	—	—	—	(149)	—	(149)
Depreciation, depletion and amortization[c]	(2,274)	(97)	—	(23)	(2,394)	—	(2,394)
Technical support and other	(38)	(9)	—	(10)	(57)	—	(57)
Total expenses	(3,845)	(179)	—	(104)	(4,128)	—	(4,128)
Results before income taxes	673	128	—	39	840	—	840
Income tax (provision) benefit	(6)	(32)	—	12	(26)	—	(26)
Results of operations	$ 667	$ 96	$ —	$ 51	$ 814	$ —	$ 814
Year Ended December 31, 2018							
Revenues and other income:							
Sales	$ 4,842	$ 383	$ 196	$ 402	$ 5,823	$ —	$ 5,823
Other income[a]	81	—	255	104	440	—	440
Total revenues and other income	4,923	383	451	506	6,263	—	6,263
Expenses:							
Production costs	(1,371)	(68)	(12)	(180)	(1,631)	—	(1,631)
Exploration expenses[b]	(245)	(51)	—	7	(289)	—	(289)
Depreciation, depletion and amortization[c]	(2,247)	(117)	(8)	(102)	(2,474)	—	(2,474)
Technical support and other	(49)	(5)	—	(6)	(60)	—	(60)
Total expenses	(3,912)	(241)	(20)	(281)	(4,454)	—	(4,454)
Results before income taxes	1,011	142	431	225	1,809	—	1,809
Income tax (provision) benefit	19	(38)	(163)	(124)	(306)	—	(306)
Results of operations	$ 1,030	$ 104	$ 268	$ 101	$ 1,503	$ —	$ 1,503
Year Ended December 31, 2017							
Revenues and other income:							
Sales	$ 3,050	$ 45	$ 431	$ 282	$ 3,808	$ 423	$ 4,231
Transfers	—	344	—	—	344	—	344
Other income[a]	74	—	—	38	112	(43)	69
Total revenues and other income	3,124	389	431	320	4,264	380	4,644
Expenses:							
Production costs	(985)	(84)	(44)	(152)	(1,265)	(272)	(1,537)
Exploration expenses[b]	(153)	—	—	(254)	(407)	—	(407)
Depreciation, depletion and amortization[c]	(2,105)	(134)	(21)	(273)	(2,533)	(6,676)	(9,209)
Technical support and other	(28)	(4)	(4)	(25)	(61)	—	(61)
Total expenses	(3,271)	(222)	(69)	(704)	(4,266)	(6,948)	(11,214)
Results before income taxes	(147)	167	362	(384)	(2)	(6,568)	(6,570)
Income tax (provision) benefit	(1)	(50)	(333)	13	(371)	1,674	1,303
Results of operations	$ (148)	$ 117	$ 29	$ (371)	$ (373)	$ (4,894)	$ (5,267)

[a] Includes net gain (loss) on dispositions (see **Note 5**). In 2018 and 2017 this also includes revisions to asset retirement costs primarily due to changes in U.K. estimated costs as well as timing of abandonment activities.

[b] Includes exploratory dry well costs, unproved property impairments, and other.

[c] Includes long-lived asset impairments (see **Note 11**).

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Results of Operations for Oil and Gas Producing Activities

The following reconciles results of operations for oil and gas producing activities to segment income:

(In millions)	Year Ended December 31, 2019	2018	2017
Results of operations	$ 814	$ 1,503	$ (5,267)
Discontinued operations	—	—	4,894
Results of continuing operations	814	1,503	(373)
Items not included in results of oil and gas operations, net of tax:			
Marketing income and other non-oil and gas producing related activities	(141)	(170)	(107)
Income from equity method investments	87	214	229
Items not allocated to segment income, net of tax:			
Loss (gain) on asset dispositions and other	—	(304)	(79)
Long-lived asset impairments	24	103	475
Unrealized loss (gain) on derivatives	124	(265)	81
Segment income	$ 908	$ 1,081	$ 226

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

U.S. GAAP prescribes guidelines for computing the standardized measure of future net cash flows and changes therein relating to estimated proved reserves, giving very specific assumptions to be made such as the use of a 10% discount rate and an unweighted average of commodity prices in the prior 12-month period using the closing prices on the first day of each month as well as current costs applicable at the date of the estimate. These and other required assumptions have not always proved accurate in the past, and other valid assumptions would give rise to substantially different results. In addition, the 10% discount rate required to be used is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the oil and natural gas industry in general. This information is not the fair value nor does it represent the expected present value of future cash flows of our crude oil and condensate, natural gas liquids, and natural gas reserves.

(In millions)	U.S.	E.G.	Libya	Other Int'l	Total
Year Ended December 31, 2019					
Future cash inflows	$ 40,487	$ 1,812	$ —	$ —	$ 42,299
Future production and support costs	(14,167)	(838)	—	—	(15,005)
Future development costs	(7,561)	(18)	—	—	(7,579)
Future income tax expenses	(1,085)	(280)	—	—	(1,365)
Future net cash flows	$ 17,674	$ 676	$ —	$ —	$ 18,350
10% annual discount for timing of cash flows	(7,416)	(179)	—	—	(7,595)
Standardized measure of discounted future net cash flows-related to continuing operations	$ 10,258	$ 497	$ —	$ —	$ 10,755
Year Ended December 31, 2018					
Future cash inflows	$ 49,054	$ 2,218	$ —	$ 1,813	$ 53,085
Future production and support costs	(15,995)	(878)	—	(876)	(17,749)
Future development costs	(7,729)	(12)	—	(1,072)	(8,813)
Future income tax expenses	(1,967)	(355)	—	275	(2,047)
Future net cash flows	$ 23,363	$ 973	$ —	$ 140 [(a)]	$ 24,476
10% annual discount for timing of cash flows	(10,653)	(254)	—	100	(10,807)
Standardized measure of discounted future net cash flows-related to continuing operations	$ 12,710	$ 719	$ —	$ 240	$ 13,669
Year Ended December 31, 2017					
Future cash inflows	$ 36,480	$ 1,966	$ 10,303	$ 1,403	$ 50,152
Future production and support costs	(14,796)	(748)	(931)	(821)	(17,296)
Future development costs	(6,987)	(7)	(501)	(1,247)	(8,742)
Future income tax expenses	(786)	(274)	(8,387)	496	(8,951)
Future net cash flows	$ 13,911	$ 937	$ 484	$ (169) [(a)]	$ 15,163
10% annual discount for timing of cash flows	(7,009)	(235)	(224)	168	(7,300)
Standardized measure of discounted future net cash flows-related to continuing operations	$ 6,902	$ 702	$ 260	$ (1)	$ 7,863

[(a)] Future cash flows for Other International reflects the impact of future abandonment costs related to the U.K.

Supplementary Information on Oil and Gas Producing Activities (Unaudited)

Changes in the Standardized Measure of Discounted Future Net Cash Flows

(In millions)	Year Ended December 31, 2019	2018	2017
Sales and transfers of oil and gas produced, net of production and support costs	$ (3,345)	$ (4,135)	$ (2,853)
Net changes in prices and production and support costs related to future production	(3,569)	6,342	4,916
Extensions, discoveries and improved recovery, less related costs	718	998	661
Development costs incurred during the period	1,727	1,240	1,027
Changes in estimated future development costs	278	(330)	183
Revisions of previous quantity estimates[a]	7	(501)	497
Net changes in purchases and sales of minerals in place	(200)	(3,035)	102
Accretion of discount	1,315	1,175	698
Net change in income taxes	155	4,052	(1,245)
Net change for the year	(2,914)	5,806	3,986
Beginning of the year	13,669	7,863	3,877
End of the year	$ 10,755	$ 13,669	$ 7,863

[a] Includes amounts resulting from changes in the timing of production.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) was carried out under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. As of the end of the period covered by this Report based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective as of December 31, 2019.

Management's Annual Report on Internal Control Over Financial Reporting

See "Management's Report on Internal Control over Financial Reporting" under Item 8 of this Form 10-K.

Attestation Report of the Registered Public Accounting Firm

See "Report of Independent Registered Public Accounting Firm" under Item 8 of this Form 10-K.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2019, there were no changes in our internal control over financial reporting that have materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item is incorporated by reference to "Proposal 1: Election of Directors," "Corporate Governance—Committees of the Board" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement for the 2020 Annual Meeting of Stockholders, to be filed with the SEC within 120 days of December 31, 2019 (the "2020 Proxy Statement").

See "Executive Officers of the Registrant" under Item 1 of this Form 10-K for information about our executive officers.

Our Code of Ethics for Senior Financial Officers, which applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, is available on our website at www.marathonoil.com under Investors—Corporate Governance. You may request a printed copy free of charge by sending a request to the Corporate Secretary. We intend to disclose any amendments and any waivers to our Code of Ethics for Senior Financial Officers on our website at www.marathonoil.com under Investors —Corporate Governance within four business days. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

Item 11. Executive Compensation

Information required by this item is incorporated by reference to "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "Compensation Committee Report," "Director Compensation," "Compensation Discussion and Analysis" and "Executive Compensation" in the 2020 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Portions of information required by this item are incorporated by reference to "Security Ownership of Certain Beneficial Owners and Management" in the 2020 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2019 with respect to shares of Marathon Oil common stock that may be issued under our existing equity compensation plans:

- Marathon Oil Corporation 2019 Incentive Compensation Plan (the "2019 Plan")
- Marathon Oil Corporation 2016 Incentive Compensation Plan (the "2016 Plan")
- Marathon Oil Corporation 2012 Incentive Compensation Plan (the "2012 Plan") – No additional awards will be granted under this plan.
- Marathon Oil Corporation 2007 Incentive Compensation Plan (the "2007 Plan") – No additional awards will be granted under this plan.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights[(b)]	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by stockholders	6,546,401 [(a)]	$ 23.55	30,911,537 [(c)]

(a) Includes the following:

- No stock options outstanding under the 2019 Plan; 2,044,463 stock options outstanding under the 2016 Plan; 2,494,866 stock options outstanding under the 2012 Plan; 989,835 stock options outstanding under the 2007 Plan;
- 181,982 common stock units that have been credited to non-employee directors pursuant to the annual director stock award program established under the 2019 Plan, 2016 Plan, 2012 Plan and 2007 Plan. Common stock units credited under the 2019 Plan, 2016 Plan, 2012 Plan and 2007 Plan were nil 153,119, nil, and 28,863, respectively;
- 12,263 and 647,889 outstanding restricted stock units granted to non-officers under the 2019 Plan and 2016 Plan as of December 31, 2019, respectively. Additionally, 175,103 outstanding restricted stock units granted to officers under the 2016 Plan;
- In addition to the awards reported above, 6,060,945 and 276,719 shares of restricted stock were issued and outstanding as of December 31, 2019, but subject to forfeiture restrictions under the 2016 Plan and 2019 Plan, respectively.

(b) The weighted-average exercise prices do not take the restricted stock units or common stock units into account as these awards have no exercise price.

(c) Reflects the shares available for issuance under the 2019 Plan. No more than 30,775,974 of these shares may be issued for awards other than stock options or stock appreciation rights. In addition, shares related to grants that are forfeited, terminated, canceled or expire unexercised shall again immediately become available for issuance.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item is incorporated by reference to “Transactions with Related Persons,” and “Proposal 1: Election of Directors—Director Independence” in the 2020 Proxy Statement.

Item 14. Principal Accountant Fees and Services

Information required by this item is incorporated by reference to “Proposal 2: Ratification of Independent Auditor for 2020“ in the 2020 Proxy Statement.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Documents Filed as Part of the Report

1. Financial Statements – See Part II, Item 8. of this Annual Report on Form 10-K.
2. Financial Statement Schedules – The audited financial statements and related footnotes of Alba Plant LLC, our equity method investment, are being filed within Exhibit 99.9 in accordance with Rule 3-09 of Regulation S-X. All other financial statement schedules required under SEC rules but not included in this Annual Report on Form 10-K are omitted because they are not applicable or the required information is contained in the consolidated financial statements or notes thereto.
3. Exhibits – The information required by this Item 15 is incorporated by reference to the Exhibit Index accompanying this Annual Report on Form 10-K.

Item 16. Form 10-K Summary

None.

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.

February 20, 2020 MARATHON OIL CORPORATION

By: /s/ GARY E. WILSON

Gary E. Wilson

Vice President, Controller and Chief Accounting Officer

POWER OF ATTORNEY

Each person whose signature appears below appoints Lee M. Tillman, Dane E. Whitehead, and Gary E. Wilson, and each of them, as 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, with full power and authority to each of said attorneys-in-fact and agents to do and perform each and every act whatsoever that is necessary, appropriate or advisable in connection with any or all of the above-described matters and 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 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 February 20, 2020 on behalf of the registrant and in the capacities indicated.

Signature	Title
/s/ LEE M. TILLMAN Lee M. Tillman	Chairman, President and Chief Executive Officer
/s/ DANE E. WHITEHEAD Dane E. Whitehead	Executive Vice President and Chief Financial Officer
/s/ GARY E. WILSON Gary E. Wilson	Vice President, Controller and Chief Accounting Officer
/s/ GREGORY H. BOYCE Gregory H. Boyce	Director
/s/ CHADWICK C. DEATON Chadwick C. Deaton	Director
/s/ MARCELA E. DONADIO Marcela E. Donadio	Director
/s/ JASON B. FEW Jason B. Few	Director
/s/ DOUGLAS L. FOSHEE Douglas L. Foshee	Director
/s/ M.ELISE HYLAND M. Elise Hyland	Director
/s/ J.KENT WELLS J. Kent Wells	Director

Exhibit Index

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated) Form	Exhibit	Filing Date
1	**Underwriting Agreement**			
1.1	Bond Purchase Agreement, dated as of November 28, 2017, between Marathon Oil Corporation, the Parish of St. John the Baptist, State of Louisiana, and Morgan Stanley & Co. LLC.	10-K	1.1	2/22/2018
2	**Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession**			
2.1	Share Purchase Agreement, dated as of March 8, 2017, by and among Marathon Oil Dutch Holdings B.V., as Seller, and 10084751 Canada Limited, as a Buyer and Canadian Natural Resources Limited, as a Buyer, in respect of Marathon Oil Canada Corporation.	10-Q	10.1	5/5/2017
3	**Articles of Incorporation and By-laws**			
3.1	Restated Certificate of Incorporation of Marathon Oil Corporation	8-K	3.1	6/1/2018
3.2	Marathon Oil Corporation By-laws (Amended and restated as of February 24, 2016)	10-Q	3.2	8/4/2016
3.3	Specimen of Common Stock Certificate	10-K	3.3	2/28/2014
4	**Instruments Defining the Rights of Security Holders, Including Indentures**			
4.1	Indenture, dated as of February 26, 2002, between Marathon Oil Corporation and The Bank of New York Trust Company, N.A., successor in interest to JPMorgan Chase Bank as Trustee, relating to senior debt securities of Marathon Oil Corporation. Pursuant to CFR 229.601(b)(4)(iii), instruments with respect to long-term debt issues have been omitted where the amount of securities authorized under such instruments does not exceed 10% of the total consolidated assets of Marathon Oil. Marathon Oil hereby agrees to furnish a copy of any such instrument to the Securities and Exchange Commission upon its request	10-K	4.2	2/28/2014
4.2*	Description of Registrants Securities			
10	**Material Contracts**			
10.1	Amended and Restated Credit Agreement, dated as of May 28, 2014, among Marathon Oil Corporation, as borrower, The Royal Bank of Scotland plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein	8-K	4.1	6/2/2014
10.2	First Amendment, dated as of May 5, 2015, to the Amended and Restated Credit Agreement dated as of May 28, 2014, by and among Marathon Oil Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein	10-Q	10.1	5/7/2015
10.3	Incremental Commitments Supplement, dated as of March 4, 2016, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015, among Marathon Oil Corporation, as borrower, the lenders party thereto, The Royal Bank of Scotland Plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, and JPMorgan Chase Bank, N.A., as administrative agent.	8-K	99.1	3/8/2016

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated)		
		Form	Exhibit	Filing Date
10.4	Second Amendment, dated as of June 22, 2017, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015, and supplemented by the Incremental Commitments Supplement dated as of March 4, 2016, among Marathon Oil Corporation, as borrower, the lenders party thereto, The Royal Bank of Scotland Plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, and JPMorgan Chase Bank, N.A., as administrative agent.	8-K	99.1	6/23/2017
10.5	Incremental Commitment Supplement, dated as of July 11, 2017, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015, supplemented by the Incremental Commitments Supplement dated as of March 4, 2016, and amended by the Second Amendment dated as of June 22, 2017, among Marathon Oil Corporation, as borrower, the lenders party thereto, The Royal Bank of Scotland Plc, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, and JPMorgan Chase Bank, N.A., as administrative agent.	10-Q	10.2	8/3/2017
10.6	Third Amendment, dated as of October 18, 2018, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015 and the Second Amendment dated as of June 22, 2017 and as supplemented by the Incremental Commitments Supplement dated as of March 4, 2016 and Incremental Commitments Supplement dated as July 11, 2017, among Marathon Oil Corporation, as borrower, the lenders party thereto, Mizuho Bank, Ltd, as syndication agent, Citibank, N.A., Morgan Stanley Senior Funding, Inc. and The Bank of Nova Scotia, as documentation agents, and JPMorgan Chase Bank, N.A., as administrative agent	8-K	99.1	10/22/2018
10.7	Fourth Amendment, dated as of September 24, 2019, to the Amended and Restated Credit Agreement dated as of May 28, 2014, as amended by the First Amendment dated as of May 5, 2015, the Second Amendment dated as of June 22, 2017, and the Third Amendment dated as of October 18, 2018 and as supplemented by the Incremental Commitments Supplement dated as of March 4, 2016 and Incremental Commitments Supplement dated as July 11, 2017, among Marathon Oil Corporation, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions named therein	8-K	10.1	9/24/2019
10.8†	Marathon Oil Corporation 2019 Incentive Compensation Plan	DEF 14A	App. A	4/12/2019
10.9†	2019 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers	10-Q	10.1	8/8/2019
10.10†	2019 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers	10-Q	10.2	8/8/2019
10.11†	2019 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Section 16 Officers	10-Q	10.3	8/8/2019
10.12†	2019 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Non-Employee Directors	10-Q	10.4	8/8/2019

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated)		
		Form	Exhibit	Filing Date
10.13†*	2019 Form of Marathon Oil Corporation 2019 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers			
10.14†	Marathon Oil Corporation 2016 Incentive Compensation Plan	DEF 14A	App. A	4/7/2016
10.15†	2019 Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers	10-Q	10.1	5/2/2019
10.16†	2019 Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers	10-Q	10.2	5/2/2019
10.17†	2019 Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Section 16 Officers	10-Q	10.3	5/2/2019
10.18†	2019 Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers	10-Q	10.4	5/2/2019
10.19†	Summary Director Compensation Arrangement, effective 2019	10-Q	10.5	5/2/2019
10.20†	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers (3-year cliff vesting)	8-K/A	10.1	10/6/2016
10.21†	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers (3-year prorata vesting)	10-K	10.6	2/24/2017
10.22†	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers	10-K	10.7	2/24/2017
10.23†	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Non-Employee Directors (3-year cliff vesting)	10-K	10.8	2/24/2017
10.24†	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Restricted Stock Unit Award Agreement for Non-Employee Canadian Directors (3-year cliff vesting)	10-K	10.9	2/24/2017
10.25†	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers	10-K	10.12	2/22/2018
10.26†	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Performance Unit Award Agreement for Officers	10-K	10.13	2/22/2018
10.27†	Marathon Oil Corporation 2012 Incentive Compensation Plan	DEF 14A	App. III	3/8/2012
10.28†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Non-Qualified Stock Option Award Agreement	8-K	10.1	8/1/2014
10.29†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers	10-Q	10.1	5/7/2014
10.30†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers	10-Q	10.2	5/7/2014
10.31†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Initial CEO Option Grant Agreement	10-Q	10.1	11/6/2013
10.32†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers (3-year prorata vesting)	10-K	10.5	2/22/2013

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated)		
		Form	Exhibit	Filing Date
10.33†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Officers (3-year prorata vesting)	10-K	10.6	2/22/2013
10.34†	Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.5	2/29/2012
10.35†	Form of Marathon Oil Corporation 2007 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Officers	10-K	10.6	2/29/2012
10.36†	Form of Marathon Oil Corporation 2007 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers	10-K	10.5	2/28/2011
10.37†	Marathon Oil Corporation Deferred Compensation Plan for Non-Employee Directors (Amended and Restated as of December 20, 2016)	10-K	10.29	2/24/2017
10.38†	Marathon Oil Company Deferred Compensation Plan Amended and Restated Effective June 30, 2011	10-K	10.32	2/29/2012
10.39†	Marathon Oil Company Excess Benefit Plan Amended and Restated	10-K	10.31	2/29/2012
10.40†	Marathon Oil Corporation Officer Change in Control Severance Benefits Plan (as amended, effective October 30, 2019)	10-Q	10.1	11/7/2019
10.41†	Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts	10-K	10.10	2/28/2011
10.42†	Marathon Oil Corporation Executive Tax, Estate, and Financial Planning Program, Amended and Restated, Effective January 1, 2009	10-K	10.32	2/27/2009
10.43	Tax Sharing Agreement dated as of May 25, 2011 among Marathon Oil Corporation, Marathon Petroleum Corporation and MPC Investment LLC	8-K	10.1	5/26/2011
21.1*	List of Significant Subsidiaries			
23.1*	Consent of Independent Registered Public Accounting Firm			
23.2*	Consent of Independent Registered Public Accounting Firm			
23.3*	Consent of Ryder Scott Company, L.P., independent petroleum engineers and geologists			
23.4*	Consent of Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists			
31.1*	Certification of President and Chief Executive Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934			
31.2*	Certification of Chief Financial Officer pursuant to Rule 13(a)-14 and 15(d)-14 under the Securities Exchange Act of 1934			
32.1*	Certification of President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350			
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350			
99.1*	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2018			
99.2*	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2018			
99.3	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2017	10-K	99.2	2/21/2019

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated) Form	Exhibit	Filing Date
99.4	Summary report of audits performed by Netherland, Sewell & Associates, Inc., independent petroleum engineers and geologists for 2016	10-K	99.7	2/22/2018
99.9*	Alba Plant, LLC financial statements as of December 31, 2019			
101.INS*	XBRL Instance Document - the XBRL Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document			
101.SCH*	XBRL Taxonomy Extension Schema			
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase			
101.DEF*	XBRL Taxonomy Extension Definition Linkbase			
101.LAB*	XBRL Taxonomy Extension Label Linkbase			
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase			
104*	Cover Page Interactive Data File, formatted in iXBRL and contained in Exhibit 101			

*	Filed herewith.
†	Management contract or compensatory plan or arrangement.

Corporate Information

Corporate Headquarters
5555 San Felipe Street
Houston, TX 77056-2723

Marathon Oil Corporation Web Site
www.marathonoil.com

Investor Relations Office
5555 San Felipe Street
Houston, TX 77056-2723

Guy Baber, VP Investor Relations
+1 713-296-1892

Notice of Annual Meeting
The 2020 Annual Meeting of Stockholders will be held in Houston, Texas, on May 27, 2020.

Independent Accountants
PricewaterhouseCoopers LLP
1000 Louisiana Street, Suite 5800
Houston, TX 77002-5021

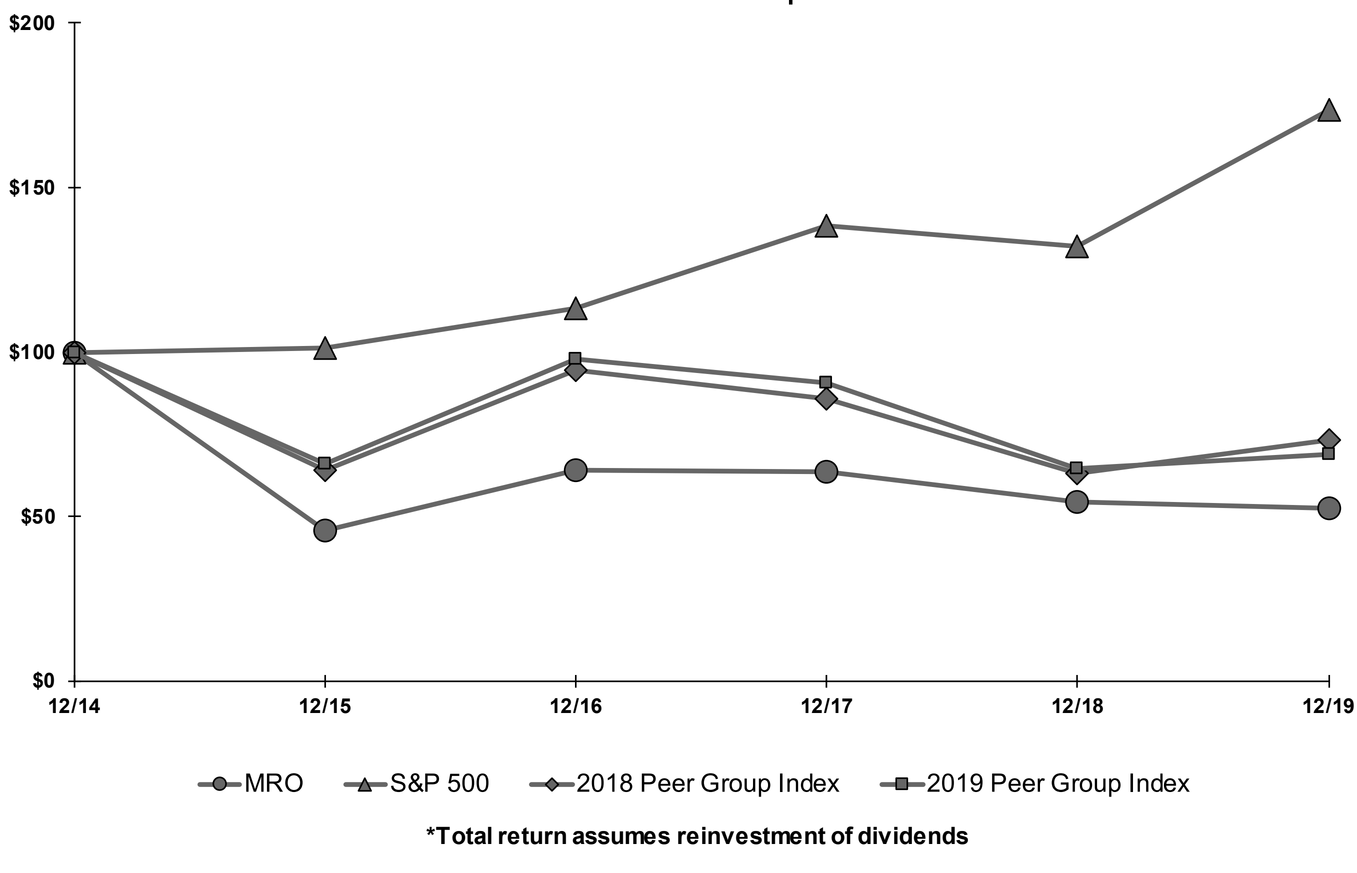
Stock Exchange Listing
New York Stock Exchange

Common Stock Symbol
MRO

Stock Transfer Agent
Computershare
211 Quality Circle, Suite 210
College Station, TX 77845
888-843-5542 (Toll free - U.S., Canada, Puerto Rico)
+1 781-575-4735 (non-U.S.)
web.queries@computershare.com

Stockholder Return Performance Graph
The line graph below compares the yearly change in cumulative total stockholder return for our common stock with the cumulative total return of the Standard & Poor's 500 Stock Index ("S&P 500"), the Peer Group Index shown in our 2019 Annual Report (the "2019 Peer Group"), and the Peer Group Index shown in our 2018 Annual Report (the "2018 Peer Group"). We use a Peer Group Index because there is no relevant published industry or line-of-business index that reflects the companies against which we compete as an independent exploration and production company. The 2019 Peer Group Index is comprised of Apache Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Continental Resources, Inc., Devon Energy Corporation, Encana Corporation, EOG Resources, Inc., Hess Corporation, Murphy Oil Corporation, Noble Energy, Inc., and Pioneer Natural Resources Company. In 2019, Anadarko Petroleum Corporation was removed because of its acquisition and replaced with Cimarex Energy Co.

Comparison of Cumulative Total Return on $100
Invested In Marathon Oil Common Stock on December 31, 2014
vs.
***S&P 500 and Peer Group Index**



***Total return assumes reinvestment of dividends**

Company Information

Board of Directors

Gregory H. Boyce
Independent Lead Director
Former Executive Chairman, Peabody Energy Corporation

Chadwick C. Deaton
Former Executive Chairman, Baker Hughes Incorporated

Marcela E. Donadio
Former Partner, Ernst & Young, LLP

Jason B. Few
President, CEO and Chief Commercial Officer, Fuelcell Energy, Inc.

Douglas L. Foshee
Founder and Owner, Sallyport Investments, LLC
Former Chairman, President and CEO, El Paso Corporation

M. Elise Hyland
Former Senior Vice President, EQT Corporation

J. Kent Wells
Former CEO and President, Fidelity Exploration & Production Company and Vice Chairman of MDU Resources

Lee M. Tillman
Chairman, President and CEO, Marathon Oil Corporation

Executive Officers

Lee M. Tillman
Chairman, President and Chief Executive Officer

Dane E. Whitehead
Executive Vice President and Chief Financial Officer

T. Mitchell Little
Executive Vice President, Operations

Patrick J. Wagner
Executive Vice President, Corporate Development and Strategy

Reginald D. Hedgebeth
Excecutive Vice President, General Counsel, Secretary and Chief Administrative Officer

Gary E. Wilson
Vice President, Controller and Chief Accounting Officer

Forward-Looking Statements and Other Items

This annual report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation: the Company's future capital program and the allocation thereof, returns, organic free cash flow, 2020 balance sheet, margins and asset quality.

While the Company believes that its assumptions concerning future events are reasonable, we can give no assurance that these expectations will prove to be correct. A number of factors could cause results to differ materially from those indicated by such forward-looking statements including, but not limited to: conditions in the oil and gas industry, including supply/demand levels for crude oil and condensate, NGLs, natural gas and synthetic crude oil and the resulting impact on price; changes in expected reserve or production levels; changes in political or economic conditions in the U.S and Equatorial Guinea, including changes in foreign currency exchange rates, interest rates, inflation rates, and global and domestic market conditions; risks relating to our hedging activities; capital available for exploration and development; drilling and operating risks; well production timing; availability of drilling rigs, materials and labor, including the costs associated therewith; difficulty in obtaining necessary approvals and permits; non-performance by third parties of their contractual obligations; unforeseen hazards such as weather conditions, health pandemics, acts of war or terrorist acts and the governmental or military response thereto; cyber-attacks; changes in safety, health, environmental, tax and other regulations; other geological, operating and economic considerations; and the risk factors, forward-looking statements and challenges and uncertainties described in the Company's 2019 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases available at www.marathonoil.com. Except as required by law, the Company assumes no duty to revise or update any forward-looking statements whether as a result of new information, future events or otherwise.

The letter in this annual report includes non-GAAP financial measures, including organic free cash flow. Reconciliations of the differences between non-GAAP financial measures used in the letter and their most directly comparable GAAP financial measures are available at www.marathonoil.com in the 4Q19 Investor Packet.