FORM 10-K

MARATHON OIL CORP - MRO

Filed: February 21, 2019 (period: December 31, 2018)

Annual report with a comprehensive overview of the company

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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2018

Commission file number 1-5153

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, TX 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	Name of each exchange on which registered
Common Stock, par value $1.00	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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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, 2018: $17,781 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 818,504,459 shares of Marathon Oil Corporation Common Stock outstanding as of February 14, 2019.

Documents Incorporated By Reference:
Portions of the registrant's proxy statement relating to its 2019 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.

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.

bcf – Billion cubic feet.

boe – Barrels of oil equivalent.

btu – British thermal unit, an energy equivalence measure.

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.

Development Capital Budget – Includes expenditures, investments and costs associated with the Capital Budget excluding resource play leasing and 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.

E&P – Exploration and production.

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

IRS – United States Internal Revenue Service.

Kurdistan – Kurdistan Region of Iraq

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.

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.

MPC – Marathon Petroleum Corporation – the separate independent company, which owns and operates the refining, marketing and transportation operations.

mt – metric tonnes

mtd – metric tonnes per day.

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.

OECD – Organization for Economic Cooperation and Development.

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.

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, Anadarko (basin), Canadian (and) Kingfisher (counties).

TD – Total depth or the bottom of a drilled hole.

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

U.K. – United Kingdom.

U.S. – United States of America.

U.S. resource plays – Consists of our unconventional properties in the Oklahoma, Eagle Ford, Bakken and Northern Delaware.

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.

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, non-core asset sales, and financial flexibility; our ability to successfully effect those strategies and the expected timing and results thereof; our 2019 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 the jurisdictions in which we operate, 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;
- 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

Item 1. Business

General

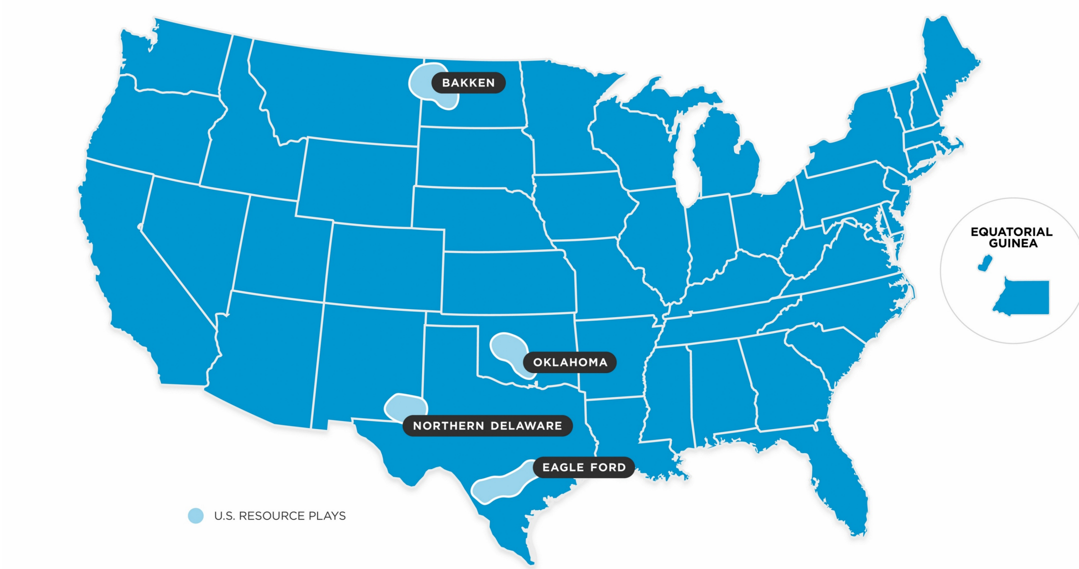
Marathon Oil Corporation (NYSE: MRO) is an independent exploration and production company based in Houston, Texas, focused on U.S. resource plays with operations in the United States, Europe and Africa. Our corporate headquarters is located at 5555 San Felipe Street, Houston, Texas 77056-2723 and our 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 and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

We were incorporated in 2001. On July 1, 2011 we became an Independent E&P after we completed the spin-off of our refining, marketing and transportation business, creating two independent energy companies: Marathon Oil and MPC.

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 peer-leading balance sheet, prioritizing sustainable cash flow generation at conservative oil 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 core operations:



* Our additional locations include the U.K, the Kurdistan Region of Iraq (executed a sales agreement in 2018) and other United States locations.

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. During the year, we renamed our United States E&P and International E&P segments to the United States and International segments. The characteristics and composition of these segments remained unchanged and there was no effect on previously reported segment information. See Note 1 for further information.

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 roughly two thirds of our acreage is located in Karnes and Atascosa Counties. Our focus is capital efficient development with a goal of maximizing returns and cash flow generation while extending our core acreage. We operate 32 central gathering and treating facilities across the play that support more than 1,600 producing wells. We also 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 our position across the rest of our acreage.

Oklahoma – With a history in Oklahoma that dates back more than 100 years, our primary focus has recently been the transition to 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.

Northern Delaware – We have been operating in the Northern Delaware basin, which is located within the greater Permian area, since we closed on two major acquisitions in 2017. These acquisitions gave us a strong foundational footprint in the region where we have the majority of our acreage in Eddy and Lea counties primarily in the Wolfcamp and Bone Spring New Mexico plays. Our focus since entering the play 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. See Item 8. Financial Statements and Supplementary Data – **Note 4** to the consolidated financial statements for further detail.

Other United States

Our remaining properties in the United States primarily consist of our newly acquired acreage in the emerging Louisiana Austin Chalk play and outside operated assets in the Gulf of Mexico, including our 3.5% overriding royalty interest in the Ursa fields. During 2018 we acquired approximately 260,000 net acres in the Louisiana Austin Chalk play at a cost of less than $850 per acre. Additionally, in the fourth quarter 2018, we entered into an agreement to sell our working interest in the Droshky field, in the Gulf of Mexico, and as a result it is classified as held for sale in the consolidated balance sheet at December 31, 2018. This transaction closed in the first quarter of 2019.

During 2018 we closed on the sale of several non-core conventional properties, see Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements for further detail.

International Segment

We are engaged in oil and gas development and production across our international locations primarily in E.G. and U.K. We include the results of our 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 2018.

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, under a long-term contract at a fixed price per btu, is processed by the LPG plant. 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 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 3.5 mmta in 2018. AMPCO had gross sales totaling approximately 1,000 mt in 2018. Methanol production is sold to customers in Europe and the U.S.

United Kingdom – Our operated assets in the U.K. sector of the North Sea are the Brae area complex where we have a 42% working interest in the South, Central, North and West Brae fields, a 39% working interest in the East Brae field, and a 28% working interest in the nearby Braemar field. We own non-operated working interests in the Foinaven area complex, consisting of a 28% working interest in the main Foinaven field, a 47% working interest in East Foinaven and a 20% working interest in the T35 and T25 fields.

Libya – 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. See Item 8. Financial Statements and Supplementary Data – **Note 5** to the consolidated financial statements for further detail.

Other International

Kurdistan Region of Iraq – We have a non-operated 15% working interest in the Atrush block located north-northwest of Erbil. During the fourth quarter of 2018, we entered into an agreement to sell our Kurdistan subsidiary, Marathon Oil KDV B.V., and as a result it is classified as held for sale in the consolidated balance sheet at December 31, 2018. We expect this transaction to close in the first half of 2019 which will complete our full country exit from Kurdistan.

Additionally during 2018, we entered into separate agreements to sell certain non-core properties in our International segment. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for information about these dispositions.

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. Other International ("Other Int'l"), includes the U.K. and the Kurdistan Region of Iraq. Approximately 86% of our proved reserves are located in OECD countries, with 84% located within the U.S.

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, 2018.

December 31, 2018	**U.S.**	**E.G.**	**Other Int'l**	**Total**
Proved Developed Reserves				
Crude oil and condensate *(mmbbl)*	287	36	22	345
Natural gas liquids *(mmbbl)*	119	22	—	141
Natural gas *(bcf)*	869	715	7	1,591
Total proved developed reserves *(mmboe)*	552	176	24	752
Proved Undeveloped Reserves				
Crude oil and condensate (*mmbbl*)	308	—	3	311
Natural gas liquids (*mmbbl*)	105	—	—	105
Natural gas (*bcf*)	684	—	—	684
Total proved undeveloped reserves (*mmboe*)	526	—	3	529
Total Proved Reserves				
Crude oil and condensate (*mmbbl*)	595	36	25	656
Natural gas liquids (*mmbbl*)	224	22	—	246
Natural gas (*bcf*)	1,553	715	7	2,275
Total proved reserves (*mmboe*)	1,078	176	27	1,281

Of the total estimated proved reserves, approximately 51% was crude oil and condensate. As of December 31, 2018, our estimated proved developed reserves totaled 752 mmboe or 59% and estimated proved undeveloped reserves totaling 529 mmboe or 41% of our total proved reserves. For additional detail on reserves, see Item 8. Financial Statements and Supplementary Data - **Supplementary Information on Oil and Gas Producing Activities**.

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							
	Oil		Natural Gas		Service Wells		Drilling Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2018								
U.S. [(a)]	4,630	2,056	1,703	655	209	21	43	18
E.G.	—	—	19	12	—	—	—	—
Other International	62	22	11	4	24	8	—	—
Total	4,692	2,078	1,733	671	233	29	43	18
2017								
U.S.	5,132	1,905	1,690	676	799	70		
E.G.	—	—	19	12	—	—		
Libya [(b)]	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		
2016								
U.S.	4,533	1,650	1,830	708	821	85		
E.G.	—	—	17	11	2	1		
Libya	1,071	175	7	1	94	16		
Total Africa	1,071	175	24	12	96	17		
Other International	62	23	35	14	23	8		
Total	5,666	1,848	1,889	734	940	110		

(a) 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.

(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.

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
2018									
U.S.	171	25	—	196	66	36	2	104	300
E.G.	—	—	—	—	—	—	1	1	1
Other International	—	—	—	—	—	—	—	—	—
Total	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
2016									
U.S.	64	12	—	76	70	27	3	100	176
E.G.	—	—	—	—	—	—	—	—	—
Libya	—	—	—	—	—	—	1	—	—
Total Africa	—	—	—	—	—	—	1	1	1
Other International	—	—	—	—	—	—	—	—	—
Total	64	12	—	76	70	27	4	101	177

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 in our United States and International segments as of December 31, 2018.

	Developed		Undeveloped		Developed and Undeveloped	
(In thousands)	Gross	Net	Gross	Net	Gross	Net
U.S.	1,352	1,004	484	356	1,836	1,360
E.G.	82	67	54	36	136	103
Other International	82	29	71	12	153	41
Total	1,516	1,100	609	404	2,125	1,504

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, licenses or concessions, undeveloped acreage listed in the table below will expire over the next three years. We plan to continue the terms of certain of these licenses and concession areas or retain leases through operational or administrative actions.

	Net Undeveloped Acres Expiring		
	Year Ended December 31,		
(In thousands)	2019	2020	2021
U.S.	31	64	134
E.G.[a]	36	—	—
Total	67	64	134

[a] This relates to the conclusion of our evaluation of drilling opportunities on the Rodo well in Alba Block Sub Area B, offshore E.G. and in 2018 determined that we would not pursue further activity.

Net Sales Volumes

		Africa					
	U.S.	E.G.	Libya	Other Int'l	Cont Ops	Disc Ops	Total
Year Ended December 31,							
2018							
Crude and condensate *(mbbld)*[a]	171	17	7	15	210	—	210
Natural gas liquids *(mbbld)*	55	11	—	—	66	—	66
Natural gas *(mmcfd)*[b]	429	416	5	14	864	—	864
Total sales volumes *(mboed)*	298	97	8	17	420	—	420
2017							
Crude and condensate *(mbbld)*[a]	133	21	19	12	185	—	185
Natural gas liquids *(mbbld)*	43	11	—	1	55	—	55
Natural gas *(mmcfd)*[b]	348	459	4	22	833	—	833
Synthetic crude oil *(mbbld)*[c]	—	—	—	—	—	18	18
Total sales volumes *(mboed)*	234	109	20	16	379	18	397
2016							
Crude and condensate *(mbbld)*[a]	131	20	3	12	166	—	166
Natural gas liquids *(mbbld)*	40	11	—	—	51	—	51
Natural gas *(mmcfd)*[b]	314	425	—	28	767	—	767
Synthetic crude oil *(mbbld)*[c]	—	—	—	—	—	48	48
Total sales volumes *(mboed)*	223	102	3	17	345	48	393

[a] The amounts correspond with the basis for fiscal settlements with governments, representing equity tanker liftings and direct deliveries of liquid hydrocarbons.
[b] Includes natural gas acquired for injection and subsequent resale.
[c] Upgraded bitumen excluding blendstocks.

Average Production Cost per Unit[a]

		Africa					
(Dollars per boe)	U.S.	E.G.	Libya	Other Int'l	Cont Ops	Disc Ops	Total
2018	$ 9.83	$ 1.91	$ 4.35	$ 30.02	$ 8.68	$ —	$ 8.68
2017	9.49	2.12	6.08	26.61	7.90	29.72	9.23
2016	9.84	2.17	N.M.	23.13	8.41	29.36	11.02

[a] 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.

N.M. Not meaningful information due to limited sales.

Average Sales Price per Unit[a]

		Africa					
(Dollars per unit)	U.S.	E.G.	Libya	Total	Other Int'l	Disc Ops	Total
2018							
Crude and condensate *(bbl)*	$ 63.11	$ 55.28	$ 73.75	$ 60.65	$ 70.39	$ —	$ 63.32
Natural gas liquids *(bbl)*	24.54	1.00 [b]	—	1.00	41.66	—	20.85
Natural gas *(mcf)*	2.65	0.24 [b]	4.57	0.30	8.03	—	1.58
2017							
Crude and condensate *(bbl)*	$ 49.35	$ 46.02	$ 60.72	$ 53.11	$ 52.66	$ —	$ 50.38
Natural gas liquids *(bbl)*	20.55	1.00 [b]	—	1.00	39.65	—	16.65
Natural gas *(mcf)*	2.84	0.24 [b]	5.03	0.28	6.28	—	1.51
Synthetic crude oil *(bbl)*	—	—	—	—	—	47.39	47.39
2016							
Crude and condensate *(bbl)*	$ 38.57	$ 38.85	$ 57.69	$ 40.95	$ 43.21	$ —	$ 39.23
Natural gas liquids *(bbl)*	13.15	1.00 [b]	—	1.00	26.41	—	10.68
Natural gas *(mcf)*	2.38	0.24 [b]	—	0.24	4.80	—	1.26
Synthetic crude oil *(bbl)*	—	—	—	—	—	37.57	37.57

[a] Excludes gains or losses on commodity derivative instruments.

[b] 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.

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.

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, 2018, the contracts for fixed and determinable quantities were at variable, market-based pricing and related primarily to the following commitments:

	2019	2020	2021	Thereafter	Commitment Period Through
Eagle Ford					
Crude and condensate *(mbbld)*	65	51	—	—	2020
Natural gas liquids *(mbbld)*	1	—	—	—	2020
Natural gas *(mmcfd)*	120	120	56	36	2022
Bakken					
Crude and condensate *(mbbld)*	10	10	10	5 - 10	2027
Natural gas *(mmcfd)*	3	3	3	3 - 25	2028
Northern Delaware					
Crude and condensate *(mbbld)*	21	19	—	—	2020

All of these contracts provide the options 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, as well as national oil companies. 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, 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 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 potential 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, 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 National Ambient Air Quality Standard ("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 2020-2021 time frame. The EPA may in the future designate additional areas as non-attainment, including areas in which we operate, which 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 EPA's final rule has been judicially challenged by both industry and other interested parties, and the outcome of this litigation may also impact implementation and revisions to the rule.

In November 2016, the Bureau of Land Management ("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.

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 Clean Water Act ("CWA") and its various programs. While these regulations were finalized largely as proposed in 2015, the rule has been stayed by the courts pending a substantive decision on the merits. In December 2018, EPA and the Army Corps of Engineers issued a proposed rule that, if finalized, would amend the 2015 regulations to narrow the scope of federal CWA jurisdiction. If the new proposed rule is not finalized 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**.

Concentrations of Credit Risk

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 2018, sales to Valero Marketing and Supply and Flint Hills Resources and each of their respective affiliates, each accounted for approximately 11% of our total revenues. In 2017, sales to Vitol and each of their respective affiliates accounted for approximately 10% of our total revenues. In 2016, sales to Valero Marketing and Supply, Tesoro Petroleum, and Flint Hills Resources and each of their respective affiliates accounted for approximately 13%, 11% and 10% of our total revenues.

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 2,400 active, full-time employees as of December 31, 2018.

Executive Officers of the Registrant

The executive officers of Marathon Oil and their ages as of February 1, 2019, are as follows:

Lee M. Tillman	57	Chairman, President and Chief Executive Officer
Dane E. Whitehead	57	Executive Vice President and Chief Financial Officer
T. Mitch Little	55	Executive Vice President—Operations
Reginald D. Hedgebeth	51	Senior Vice President, General Counsel and Secretary
Patrick J. Wagner	54	Executive Vice President—Corporate Development and Strategy
Gary E. Wilson	57	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 senior vice president, general counsel and secretary in 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, exploration. 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 and 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 our Investor Relations office. 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;
- the effect of conservation efforts;
- epidemics or pandemics;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxes; 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, natural gas and our historical synthetic crude oil reserves 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, 2018, 2017 and 2016, as well as other conditions in existence at those dates. The table below provides the 2018 SEC pricing for certain benchmark prices:

	2018 SEC Pricing	
WTI Crude oil (per bbl)	$	65.56
Henry Hub natural gas (per mmbtu)	$	3.05
Brent crude oil (per bbl)	$	72.70
Mont Belvieu NGLs (per bbl)	$	26.63

If annual SEC crude oil benchmark prices (see table above) were to decrease to approximately $45 per bbl, or 30% below average prices used to estimate 2018 proved reserves, we would not expect price related reserve revisions to have a material impact on proved reserve volumes. 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 will 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 will 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, including abandonment obligations, 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, including abandonment 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.

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.

We may incur substantial capital expenditures and operating costs as a result of compliance with and changes in environmental, health, safety and security laws and regulations, and, as a result, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Our businesses are 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 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. 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. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products, our operating results will 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 countries where we operate, including the U.S. and the European Union. 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. The EPA has also finalized regulations targeting new sources of methane emissions from the oil and gas industry. 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 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, 2018, our total debt was $5.5 billion, with our next debt maturity in the amount of $600 million due in 2020. 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 16** to the consolidated financial statements for a discussion of debt obligations.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital, which 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, 2018, our corporate credit ratings were: Standard & Poor's Global Ratings Services BBB- (positive); Fitch Ratings BBB (stable); and Moody's Investor Services, Inc. Ba1 (positive). The credit rating process is contingent upon a number of factors, many of which are beyond our control. A downgrade of our credit ratings 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 and natural gas, we, from time to time, enter into crude oil 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**.

Worldwide 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 global markets could have a material adverse effect on us. A total of 29% of our crude oil and condensate, NGLs and natural gas related to continuing operations in 2018 was derived from production outside the U.S. and 16% of our proved reserves of crude oil and condensate, NGLs and natural gas as of December 31, 2018 were located outside the U.S. We are, therefore, 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 many risks associated with operations in countries such as E.G., and the Kurdistan Region of Iraq including:

- changes in governmental policies relating to crude oil and condensate, NGLs or natural gas and taxation;
- other political, economic or diplomatic developments and international monetary fluctuations;
- political and economic instability, war, acts of terrorism, armed conflict and civil disturbances;
- the possibility that a 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; and
- fluctuating currency values, hard currency shortages and currency controls.

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 from delivering 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 law 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 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 crude oil 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. For example, due to historical hurricane activity, the availability of insurance coverage for windstorms has changed and, in some instances, it is uneconomical. As a result, our exposure to losses from future windstorm activity has increased.

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 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. 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.

In connection with our separation from MPC, MPC agreed to indemnify us for certain liabilities. However, there can be no assurance that the indemnity will be sufficient to protect us against the full amount of such liabilities, or that MPC's ability to satisfy its indemnification obligations will not be impaired in the future.

Pursuant to the Separation and Distribution Agreement and the Tax Sharing Agreement we entered into with MPC in connection with the spin-off, MPC agreed to indemnify us for certain liabilities. However, third parties could seek to hold us responsible for any of the liabilities that MPC agreed to retain or assume, and there can be no assurance that the indemnification from MPC will be sufficient to protect us against the full amount of such liabilities, or that MPC will be able to fully satisfy its indemnification obligations. In addition, even if we ultimately succeed in recovering from MPC any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves.

The spin-off could result in substantial tax liability.

We obtained a private letter ruling from the IRS substantially to the effect that the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections 355 and 368 and related provisions of the U.S. Internal Revenue Code of 1986, as amended (the "Code"). If the factual assumptions or representations made in the request for the private letter ruling prove to have been inaccurate or incomplete in any material respect, then we will not be able to rely on the ruling. Furthermore, the IRS does not rule on whether a distribution such as the spin-off satisfies certain requirements necessary to obtain tax-free treatment under Section 355 of the Code. Rather, the private letter ruling was based on representations by us that those requirements were satisfied, and any inaccuracy in those representations could invalidate the ruling. In connection with the spin-off, we also obtained an opinion of outside counsel, substantially to the effect that, the distribution of shares of MPC common stock in the spin-off qualified as tax free to MPC, us and our stockholders for U.S. federal income tax purposes under Sections 355 and 368 and related provisions of the Code. The opinion relied on, among other things, the continuing validity of the private letter ruling and various assumptions and representations as to factual matters made by MPC and us which, if inaccurate or incomplete in any material respect, would jeopardize the conclusions reached by such counsel in its opinion. The opinion is not binding on the IRS or the courts, and there can be no assurance that the IRS or the courts would not challenge the conclusions stated in the opinion or that any such challenge would not prevail.

If, notwithstanding receipt of the private letter ruling and opinion of counsel, the spin-off were determined not to qualify under Section 355 of the Code, each U.S. holder of our common stock who received shares of MPC common stock in the spin-off would generally be treated as receiving a taxable distribution of property in an amount equal to the fair market value of the shares of MPC common stock received. That distribution would be taxable to each such stockholder as a dividend to the extent of our accumulated earnings and profits as of the effective date of the spin-off. For each such stockholder, any amount that exceeded those earnings and profits would be treated first as a non-taxable return of capital to the extent of such stockholder’s tax basis in its shares of our common stock with any remaining amount being taxed as a capital gain. We would be subject to tax as if we had sold all the outstanding shares of MPC common stock in a taxable sale for their fair market value and would recognize taxable gain in an amount equal to the excess of the fair market value of such shares over our tax basis in such shares.

Under the terms of the Tax Sharing Agreement we entered into with MPC in connection with the spin-off, MPC is generally responsible for any taxes imposed on MPC or us and our subsidiaries in the event that the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment as a result of actions taken, or breaches of representations and warranties made in the Tax Sharing Agreement, by MPC or any of its affiliates. However, if the spin-off and/or certain related transactions were to fail to qualify for tax-free treatment because of actions or failures to act by us or any of our affiliates, we would be responsible for all such taxes.

We may issue preferred stock whose terms could dilute the voting power or reduce the value of Marathon Oil common stock.

Our restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such preferences, powers and relative, participating, optional and other rights, including preferences over Marathon Oil common stock respecting dividends and distributions, as our Board of Directors generally may determine. The terms of one or more classes or series of preferred stock could dilute the voting power or reduce the value of Marathon Oil common stock. For example, we could grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we could assign to holders of preferred stock could affect the residual value of the common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and general character of our principal crude oil and condensate, NGLs and natural gas properties and facilities, and other important physical properties have been described by segment under **Item 1. Business**.

Estimated net proved crude oil and condensate, NGLs and natural gas reserves and the basis for estimating these reserves are set forth in **Item 8. Financial Statements and Supplementary Data – Supplementary Information on Oil and Gas Producing Activities**.

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, 2018, 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 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.

As of December 31, 2018, 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.

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, 2019, there were 29,960 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 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, 2018, 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)]
10/01/18 – 10/31/18	7,151,077	$ 21.52	7,110,719	$ 1,009,043,095
11/01/18 – 11/30/18	6,260,834	$ 16.74	6,256,479	$ 904,286,215
12/01/18 – 12/31/18	6,593,370	$ 15.78	6,592,195	$ 800,286,037
Total	20,005,281	$ 18.13	19,959,393	

(a) 45,888 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 $2.0 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 $2.0 billion in July 2007, and by $1.2 billion in December 2013, for a total authorized amount of $6.2 billion. As of December 31, 2018, we have repurchased 157 million common shares at a cost of approximately $5.4 billion, excluding transaction fees and commissions. Of this total, approximately 20 million shares were acquired at a cost of approximately $362 million during the fourth quarter of 2018. The remaining share repurchase authorization as of December 31, 2018 is approximately $800 million. 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 prior to completion. Shares repurchased as of December 31, 2018 were held as treasury stock.

Item 6. Selected Financial Data

(In millions, except per share data)	Year Ended December 31, 2018	2017	2016	2015	2014
Statement of Income Data[a][b][c]					
Total revenues and other income	$ 6,582	$ 4,765	$ 3,787	$ 4,953	$ 9,646
Income (loss) from continuing operations	1,096	(830)	(2,087)	(1,701)	710
Discontinued operations	—	(4,893)	(53)	(503)	2,336
Net income (loss)	1,096	(5,723)	(2,140)	(2,204)	3,046
Per Share Data[a][b][c]					
Basic:					
Income (loss) from continuing operations	$ 1.30	$ (0.97)	$ (2.55)	$ (2.51)	$ 1.04
Discontinued operations	$ —	$ (5.76)	$ (0.06)	$ (0.75)	$ 3.44
Net income (loss)	$ 1.30	$ (6.73)	$ (2.61)	$ (3.26)	$ 4.48
Diluted:					
Income (loss) from continuing operations	$ 1.29	$ (0.97)	$ (2.55)	$ (2.51)	$ 1.04
Discontinued operations	$ —	$ (5.76)	$ (0.06)	$ (0.75)	$ 3.42
Net income (loss)	$ 1.29	$ (6.73)	$ (2.61)	$ (3.26)	$ 4.46
Statement of Cash Flows Data[b]					
Additions to property, plant and equipment related to continuing operations	$ (2,753)	$ (1,974)	$ (1,204)	$ (3,485)	$ (4,937)
Dividends paid	169	170	162	460	543
Dividends per share	$ 0.20	$ 0.20	$ 0.20	$ 0.68	$ 0.80
Balance Sheet Data at December 31					
Total assets	$ 21,321	$ 22,012	$ 31,094	$ 32,311	$ 35,983
Total long-term debt, including capitalized leases	5,499	5,494	6,581	7,268	5,285

[a] Includes impairments to producing properties of $75 million, $229 million, $67 million, $381 million and $132 million in 2018, 2017, 2016, 2015 and 2014 and impairments to unproved properties of $208 million, $246 million, $195 million, $655 million and $306 million in 2018, 2017, 2016, 2015 and 2014 (see Item 8. Financial Statements and Supplementary Data – Note 11 to the consolidated financial statements). Includes a goodwill impairment of $340 million in 2015 related to the U.S. reporting unit.

[b] We closed on the sale of our Canada business in 2017 which resulted in an after-tax non-cash impairment charge of $4.96 billion and our Angola assets and Norway business in 2014 (see Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements). The applicable periods have been recast to reflect as discontinued operations.

[c] December 31, 2016 includes the increase of a valuation allowance on certain of our deferred tax assets for $1,346 million.

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

During 2018, we continued our outstanding operational execution and capital efficiency across our multi-basin U.S. portfolio, maintained a strong balance sheet and delivered solid financial results. Total proved reserves were 1.3 billion boe and total assets were $21.3 billion at December 31, 2018. Additionally in 2018, we closed on the sale of our subsidiary, Marathon Oil Libya Limited and entered into agreements to complete a full country exit in Kurdistan. Our 2018 financial and operating results highlighted below reflect our ongoing commitment to our core strategy of continuous corporate returns improvement, sustainable cash flow generation at conservative oil prices and the return of capital to shareholders.

Key highlights include the following:

Simplifying and concentrating our portfolio

- Early in 2018 we closed on the sale of our Libya subsidiary for proceeds of approximately $450 million resulting in a gain of $255 million and received $750 million in remaining proceeds from the sale of our Canadian business.
- During 2018 we entered into agreements for the sale of our interest in the non-operated Sarsang and Atrush blocks which will complete our full country exit from Kurdistan. We expect the remaining transaction for our subsidiary Marathon Oil KDV B.V., which holds our non-operated interest in the Atrush block, to close in the first half of 2019.
- In July 2018 we closed on the sale of non-core, non-operated conventional assets in the U.S. segment for a pre-tax gain of $32 million, including three in the Gulf of Mexico, further concentrating and simplifying our portfolio.
- In Northern Delaware we acquired 1,800 net acres in New Mexico for $105 million from the Bureau of Land Management lease sale, which is synergistic with our existing footprint in the resource play.
- Captured approximately 260,000 net acres in the emerging Louisiana Austin Chalk play at a cost of less than $850 per acre.

Strengthened balance sheet and liquidity

- Returned additional capital to shareholders in 2018 by acquiring 36 million of common shares at a cost of $700 million, with $800 million of repurchase authorization remaining.
- Reduced estimated costs of our asset retirement obligations by $338 million primarily through accelerating our U.K. abandonment timing to capture favorable market conditions and through the disposition of Gulf of Mexico assets.
- Cash and cash equivalents increased approximately $900 million as a result of the sale of our Libya subsidiary and the receipt of the remaining proceeds from the sale of our Canadian business.
- Cash provided by operating activities from continuing operations increased by 63%, compared to the same period last year, to $3,234 million primarily as a result of increased price realizations and net sales volumes in our U.S. resource plays.

Financial and operational results

- Total net sales volumes for the year were 420 mboed, including 298 mboed in the U.S. Our U.S. net sales volumes increased 64 mboed and our wells to sales increased 18% compared to 2017.
- Added proved reserves of 186 mmboe for a reserve replacement ratio from continuing operations of 125%.
- Our net income per share from continuing operations was $1.30 in 2018 as compared to a net loss per share of $0.97 last year. Included in the 2018 net income are:

- An increase in revenues of approximately 39% compared to 2017, as a result of increased price realizations of 28% and a 27% increase in net sales volumes in the United States.
- Our net gain on disposal of assets increased in 2018 to $319 million due to the sale of our Libya subsidiary for $255 million.
- Production expense, taxes other than income and shipping, handling and other increased 18%, 63% and 33%, during 2018 as a result of an increase in net sales volumes across our U.S. resource plays.
- Exploration and impairment expenses decreased by $274 million to $364 million, year over year, primarily due to non-cash impairment charges on proved and unproved properties in 2017. See Item 8. Financial Statements and Supplementary Data - Note 11 to the consolidated financial statements for further detail.

Outlook

Capital Budget

On February 13, 2019 we announced our total 2019 Capital Budget of $2.6 billion, which includes approximately $2.4 billion of development capital and approximately $200 million to fund resource play leasing and exploration ("REx"). Our $2.4 billion development capital budget is 95% dedicated to the four U.S. resource plays with approximately 60% allocated to the Eagle Ford and Bakken and approximately 40% allocated to Oklahoma and the Northern Delaware.

Our 2019 Capital Budget is broken down by reportable segment in the table below:

(In millions)		Capital Budget
United States[a]	$	2,525
International and corporate other[b]		75
Total Capital Budget	$	2,600

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

Operations

Our net sales volumes increased 11% in 2018 primarily as a result of new wells to sales across all U.S. resource plays.

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	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
United States *(mboed)*	298	27 %	234	5%	223
International *(mboed)*[a]	122	(16)%	145	19%	122
Total continuing operations *(mboed)*	420	11 %	379	10%	345

[a]We closed on the sale of our Libya subsidiary in the first quarter of 2018. Years ended December 31, 2018, 2017 and 2016 includes net sales volumes relating to Libya of 8 mboed, 20 mboed and 3 mboed.

United States

Net sales volumes in the segment were higher during the year ended December 31, 2018 primarily as a result of new wells to sales across all 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	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
Equivalent Barrels *(mboed)*					
Eagle Ford	108	7%	101	(4)%	105
Bakken	84	50%	56	4%	54
Oklahoma	74	37%	54	54%	35
Northern Delaware	20	233%	6	100%	—
Other United States[a]	12	(29)%	17	(41)%	29
Total United States (mboed)	298	27%	234	5%	223

[a] Year ended December 31, 2018 includes decreases of 5 mboed, relating primarily to the disposition of certain assets in the Gulf of Mexico and conventional assets in Oklahoma in July 2018 and September 2017 and Colorado in October 2017. Additionally, year ended December 31, 2017 includes decreases of 14 mboed, consisting of the disposition of Wyoming and certain non-operated CO2 and waterflood assets in West Texas and New Mexico in 2016. See Item 8. Financial Statements and Supplementary Data - Note 5 to the consolidated financial statements for information about these dispositions.

Sales Mix - U.S. Resource Plays - 2018	Eagle Ford	Bakken	Oklahoma	Northern Delaware	Total
Crude oil and condensate	59%	85%	25%	58%	57%
Natural gas liquids	21%	8%	28%	20%	20%
Natural gas	20%	7%	47%	22%	23%

Drilling Activity - U.S. Resource Plays	2018	2017	2016
Gross Operated			
Eagle Ford:			
Wells drilled to total depth	123	182	168
Wells brought to sales	149	157	168
Bakken:			
Wells drilled to total depth	78	90	3
Wells brought to sales	80	39	13
Oklahoma:			
Wells drilled to total depth	55	86	33
Wells brought to sales	57	73	28
Northern Delaware:			
Wells drilled to total depth	69	27	—
Wells brought to sales	52	18	—

- *Eagle Ford* – Our net sales volumes were 108 mboed in 2018, which was 7% higher compared to 2017. We brought 149 gross company-operated wells to sales in 2018. In Atascosa County, we brought online 40 wells during 2018 with strong well results, demonstrating the strength of the extended core. During 2018, we generated significant cash flow, improved well productivity with annual oil growth of 7%, despite 5% fewer gross company-operated wells to sales.

- *Bakken* – Our net sales volumes of 84 mboed in 2018 represented a 50% increase over the prior year of 56 mboed. We brought 80 gross company-operated wells to sales in 2018 with continued impressive well results. During 2018, we delivered best-in-basin well performance, significant cash flow, capital efficient annual oil growth of 53%, and successful core extension tests in the Ajax, Southern Hector and Elk Creek areas. During the fourth quarter we conducted a successful core extension test in the Ajax area of Dunn County, as the four-well Gloria pad achieved strong results at an average completed well cost of approximately $5 million.

- *Oklahoma* – Our net sales volumes in 2018 increased by 37% from 2017, with net sales volumes of 74 mboed. We brought 57 gross company-operated wells to sales in 2018. In 2018, we successfully transitioned to infill development in the over-pressured STACK Meramec and SCOOP Woodford, delivering competitive returns and predictable results at various spacing designs.

- *Northern Delaware* – Our net sales volumes were 20 mboed in 2018 while bringing 52 gross company-operated wells to sales. We continue to make significant progress in improving efficiencies and midstream access for all products to protect and enhance margins. During the fourth quarter, we executed a comprehensive water management agreement covering the entire Red Hills prospect area, complementing a previously announced agreement in Eddy County.

International

Net sales volumes in the segment were lower during the year ended December 31, 2018 primarily due to the sale of our subsidiary in Libya, planned maintenance activities and natural declines in E.G. The following table provides details regarding net sales volumes for our significant operations within this segment:

Net Sales Volumes	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
Equivalent Barrels *(mboed)*					
Equatorial Guinea	97	(11)%	109	7%	102
United Kingdom[(a)]	13	(7)%	14	(18)%	17
Libya	8	(60)%	20	567%	3
Other International	4	100%	2	100%	—
Total International	122	(16)%	145	19%	122
Equity Method Investees					
LNG *(mtd)*	5,805	(10)%	6,423	9%	5,874
Methanol *(mtd)*	1,241	(10)%	1,374	1%	1,358
Condensate and LPG *(boed)*	13,034	(10)%	14,501	8%	13,430

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

- *Equatorial Guinea* – Net sales volumes in 2018 were lower than 2017 as a result of timing of liftings, natural field decline and planned maintenance activities during the year.
- *United Kingdom* – Net sales volumes in 2018 were slightly lower than 2017 primarily due to unscheduled downtime at the non-operated Foinaven complex in the fourth quarter 2018.
- *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.

Market Conditions

Crude oil and condensate and NGLs benchmarks increased in 2018 as compared to the same period in 2017. As a result, we experienced increased 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 2019. 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 commodity prices could impact us. Additional detail on market conditions, including our average price realizations and benchmarks for crude oil and condensate, NGLs and natural gas relative to our operating segments, follows.

United States

The following table presents our average price realizations and the related benchmarks for crude oil and condensate, NGLs and natural gas for 2018, 2017 and 2016.

	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
Average Price Realizations[(a)]					
Crude oil and condensate *(per bbl)*[(b)]	$ 63.11	28 %	$ 49.35	28%	$ 38.57
Natural gas liquids *(per bbl)*	24.54	19 %	20.55	56%	13.15
Natural gas *(per mcf)*[(c)]	2.65	(7)%	2.84	19%	2.38
Benchmarks					
WTI crude oil average of daily prices *(per bbl)*	$ 64.90	28 %	$ 50.85	17%	$ 43.47
LLS crude oil average of daily prices *(per bbl)*	70.04	30 %	54.04	20%	45.02
Mont Belvieu NGLs *(per bbl)*[(d)]	28.63	20 %	23.76	37%	17.40
Henry Hub natural gas settlement date average (per *mmbtu)*	3.09	(1)%	3.11	26%	2.46

(a) Excludes gains or losses on commodity derivative instruments.
(b) Inclusion of realized gains (losses) would have impacted average price realizations by $(4.60) per bbl, $0.75 per bbl, and $0.92 per bbl for 2018, 2017, and 2016.
(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) Bloomberg Finance LLP: Y-grade Mix NGL of 50% ethane, 25% propane, 10% butane, 5% isobutane and 10% 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 2018, 2017 and 2016.

	2018	Increase (Decrease)	2017	Increase (Decrease)	2016
Average Price Realizations					
Crude oil and condensate *(per bbl)*	$ 64.25	21 %	$ 53.05	27%	$ 41.70
Natural gas liquids *(per bbl)*	2.27	(28)%	3.15	49%	2.11
Natural gas *(per mcf)*	0.54	(2)%	0.55	6%	0.52
Benchmark					
Brent (Europe) crude oil *(per bbl)*[(a)]	$ 71.06	31 %	$ 54.25	25%	$ 43.55

(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.

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 NGL's 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.

Natural gas liquids – Wet gas is sold to Alba Plant LLC at a fixed-price term contract resulting in realized prices not fully tracking market price. Alba Plant LLC extracts 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 is sold to EGHoldings and AMPCO at fixed-price long term contracts resulting in realized prices not fully tracking market price. We derive additional value from the equity investment in our downstream gas processing units EG LNG and AMPCO that market LNG and methanol at market prices.

Consolidated Results of Operations: 2018 compared to 2017

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

	Year Ended December 31,	
(In millions)	2018	2017
Revenues from contracts with customers		
United States	$ 4,886	$ 3,093
International	1,016	1,154
Segment revenues from contracts with customers	$ 5,902	$ 4,247

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.

(In millions)	Year Ended December 31, 2017	Increase (Decrease) Related to Price Realizations	Increase (Decrease) Related to Net Sales Volumes	Year Ended December 31, 2018
United States Price/Volume Analysis				
Crude oil and condensate	$ 2,402	$ 861	$ 684	$ 3,947
Natural gas liquids	324	80	91	495
Natural gas	361	(30)	82	413
Other sales	6			31
Total	$ 3,093			$ 4,886
International Price/Volume Analysis				
Crude oil and condensate	$ 1,000	$ 155	$ (267)	$ 888
Natural gas liquids	15	(4)	(2)	9
Natural gas	97	(2)	(9)	86
Other sales	42			33
Total	$ 1,154			$ 1,016

Net loss on commodity derivatives decreased $22 million in 2018 from 2017. 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 index pricing and forward curves change each period. See **Note 14** to the consolidated financial statements for further information.

Marketing revenues decreased $162 million in 2018 from 2017. This decrease is the result of adopting the new revenue standard, ASC Topic 606, Revenue from Contracts with Customers during the first quarter of 2018. As a result of this standard, we have changed our presentation of marketing revenues and marketing expenses from the historical gross presentation to a net presentation. See **Note 2** to the consolidated financial statements for further information.

Income from equity method investments decreased $31 million primarily due to higher production costs and lower volumes and pricing at our E.G. LNG production facility. Our higher production costs and lower volumes were primarily driven by planned maintenance activities during the first quarter 2018.

Net gain on disposal of assets increased $261 million in 2018 from 2017. This increase was primarily related to the 2018 sale of our Libya subsidiary for a pre-tax gain of $255 million; and also includes the sale of non-core assets in the Gulf of Mexico and our International segment during the current year. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for information about these dispositions.

Other income increased $72 million in 2018 from 2017 primarily a result of the reduction of our U.K. asset retirement obligation during 2018. See Item 8. Financial Statements and Supplementary Data - **Note 12** to the consolidated financial statements for detail about our asset retirement obligation.

Production expenses increased $126 million during 2018 from 2017 primarily due to higher sales volumes across our United States segment. Our United States segment increased $149 million primarily due to higher costs as a result of increased sales volumes and new wells to sales in our developing Northern Delaware asset. International segment decreased $24 million primarily due to the sale of our subsidiary in Libya in the first quarter 2018.

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

(in millions/$ per boe)	2018		2017	
Production Expense and Production Expense Rate	**Expense**	**Rate**	**Expense**	**Rate**
United States	$ 625	$ 5.75	$ 476	$ 5.57
International	$ 215	$ 4.86	$ 239	$ 4.51

Marketing costs decreased $168 million in 2018 from 2017. This decrease is the result of adopting the new revenue standard, ASC Topic 606, Revenue from Contracts with Customers during the first quarter of 2018. As a result of this standard, we have changed our presentation of marketing revenues and marketing expenses from the historical gross presentation to a net presentation. See Note 2 to the consolidated financial statements for further information.

Shipping, handling and other operating expenses increased $144 million in 2018 from 2017 primarily as a result of increased sales volumes in our United States segment.

Exploration expenses decreased $120 million during 2018 versus the comparable 2017. The decrease was primarily due to lower unproved property impairments and dry well costs in certain non-core international properties in 2018 versus 2017. 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)	**2018**	**2017**
Exploration Expenses		
Unproved property impairments	$ 208	$ 246
Dry well costs	47	77
Geological and geophysical	21	25
Other	13	61
Total exploration expenses	$ 289	$ 409

Depreciation, depletion and amortization increased $69 million in 2018 from 2017 primarily as a result of an increase of $206 million in the United States segment primarily due to higher sales volumes across all U.S. resource plays. Offsetting this higher expense was a decrease of $131 million in our International segment primarily due to the reduction of our estimated U.K. asset retirement costs. Additionally, lower sales volumes in E.G., asset sales in Libya and Kurdistan all contributed to the lower expense during 2018. 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 (expense per boe), which is impacted by field-level changes in reserves, capitalized costs and sales volumes, can also impact our DD&A expense. Our United States DD&A rate decreased in 2018 primarily due to increased proved developed reserves in our U.S. resource plays in late 2017; as well as reduced capitalized costs relating to the Gulf of Mexico impairment charge in 2017 and the subsequent sale of these assets in 2018. The DD&A rate for International decreased with the reduction of our estimated U.K. asset retirement costs in the second half of 2018 and 2017.

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

($ per boe)	**2018**	**2017**
DD&A Rate		
United States	$ 20.39	$ 23.51
International	$ 4.44	$ 6.19

Impairments decreased $154 million in 2018 from 2017. This decrease was primarily the result of the proved property impairments in the third quarter 2017 in certain non-core international properties and certain properties in the Gulf of Mexico. See Item 8. Financial Statements and Supplementary Data - Note 11 to the consolidated financial statement for detail of proved property impairments each year.

Taxes other than income tend to increase or decrease in relation to revenue and sales volumes, primarily in the U.S. As U.S. sales volumes and revenues increased during 2018, this resulted in an increase of $116 million compared to 2017. Additionally, the State of Oklahoma approved an increase to the gross production tax from 2% to 5% on all existing and new wells for the first thirty-six months, effective July 1, 2018. The following table summarizes the components of taxes other than income:

(In millions)	Year Ended December 31, 2018		2017
Taxes other than income			
Production and severance	$ 208	$	121
Ad valorem	23		13
Other	68		49
Total taxes other than income	$ 299	$	183

General and administrative expenses increased $23 million in 2018 compared to 2017. This was primarily the result of officer and non-officer compensation, including improved performance of stock-based performance units.

Net interest and other decreased $44 million during 2018 compared to 2017. This decrease was primarily due the redemption of $1.76 billion of debt during 2017, partially offset by the termination of our forward starting interest rate swaps in 2017, which resulted in a gain of $46 million. The components of net interest and other are detailed in Item 8. Financial Statements and Supplementary Data - **Note 21** to the consolidated financial statements.

Loss on early extinguishment of debt decreased $51 million in 2018 compared to 2017 primarily due to make-whole call provisions paid upon redemption of $1.76 billion in senior unsecured notes in 2017. See Item 8. Financial Statements and Supplementary Data - **Note 16** to the consolidated financial statements for further detail.

Provision (benefit) for income taxes reflects an effective tax rate from continuing operations of 23% and 83% for 2018 and 2017. See Item 8. Financial Statements and Supplementary Data - **Note 8** to the consolidated financial statements for a discussion of the effective income tax rate.

Discontinued operations are presented net of tax. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for financial information concerning our discontinued operations.

Segment Results: 2018 compared to 2017

Segment Income (Loss)

Segment income (loss) represents income (loss) from continuing operations excluding certain items not allocated to 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. Gains or losses on dispositions, certain impairments, 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 (loss) to net income (loss):

(In millions)	Year Ended December 31, 2018	2017
United States	$ 608	$ (148)
International	473	374
Segment income (loss)	1,081	226
Items not allocated to segments, net of income taxes[a]	15	(1,056)
Income (loss) from continuing operations	1,096	(830)
Income (loss) from discontinued operations[b]	—	(4,893)
Net income (loss)	$ 1,096	$ (5,723)

[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.
[b] We sold our Canadian business in the second quarter of 2017. The Canadian business is reflected as discontinued operations in 2017.

United States segment income increased $756 million after-tax in 2018 compared to 2017 primarily due to higher price realizations and an increase in net sales volumes, which resulted in increased revenues. This increase in revenue was partially offset by an increase in our net loss on commodity derivatives. Additionally, our increase in net sales volumes resulted in a corresponding increase to production expenses, DD&A, taxes other than income, and shipping, handling and other operating expenses which partially offset the increase to revenues.

International segment income increased $99 million after-tax in 2018 compared to 2017 as a result of increased income in Other International and the U.K. primarily as a result of increased price realizations and an increase in Other International sales

volumes. Lower expenses in 2018 were primarily driven by lower DD&A expense as a result of the decrease in estimated U.K. asset retirement costs, lower E.G. sales volumes and the sale of certain Other International properties. This was partially offset by lower income in Libya due to the 2018 sale of our Libya subsidiary (see **Note 5** to the consolidated financial statements for further information).

Consolidated Results of Operations: 2017 compared to 2016

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

Year Ended December 31,

(In millions)		2017		2016
Revenues from contracts with customers				
United States	$	3,093	$	2,331
International		1,154		665
Segment revenues from contracts with customers	$	4,247	$	2,996

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.

(In millions)		Year Ended December 31, 2016	Increase (Decrease) Related to					Year Ended December 31, 2017
				Price Realizations		Net Sales Volumes		
United States Price/Volume Analysis [(a)]								
Crude oil and condensate	$	1,852	$	525	$	25	$	2,402
Natural gas liquids		189		117		18		324
Natural gas		274		58		29		361
Other sales		16						6
Total	$	2,331					$	3,093
International Price/Volume Analysis								
Crude oil and condensate	$	537	$	214	$	249	$	1,000
Natural gas liquids		9		5		1		15
Natural gas		87		4		6		97
Other sales		32						42
Total	$	665					$	1,154

(a) Year ended December 31, 2016 includes sales volumes of 14 mboed on an annualized basis relating to assets sold when compared to 2017, primarily consisting of the disposition of Wyoming and certain non-operated CO_2 and waterflood assets in West Texas and New Mexico in 2016.

Net gain (loss) on commodity derivatives decreased $30 million in 2017 from 2016. 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 index pricing and forward curves change each period. See **Note 14** to the consolidated financial statements for further information.

Marketing revenues decreased $78 million in 2017 from 2016, primarily as a result of lower marketed volumes in the United States segment due to non-core asset dispositions. Marketing activities include the purchase of commodities from third parties for resale and serve to aggregate volumes in order to satisfy transportation commitments as well as to achieve flexibility within product types and delivery points. Since the volume of marketing activity is based on market dynamics, it can fluctuate from period to period.

Income from equity method investments increased $81 million primarily due to higher price realizations from LPG at our Alba plant and methanol at our AMPCO methanol facility. Also contributing to the increase was improvement in net sales volumes primarily driven by the completion of the Alba field compression project in E.G. during the second half of 2016.

Net gain on disposal of assets decreased $331 million in 2017 from 2016. This decrease was primarily related to the sale of non-core assets in the first half of 2016 in Wyoming, West Texas and New Mexico, and the Gulf of Mexico. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for information about these dispositions.

Other income increased $25 million in 2017 from 2016. This increase was primarily a result of a downward revision in U.K. estimated asset retirement costs as well as timing of abandonment activities in the U.K. See Item 8. Financial Statements and Supplementary Data - **Note 12** to the consolidated financial statements for detail about our asset retirement obligation.

Production expenses remained nearly flat during 2017 while our sales volumes from continuing operations increased. During 2017, our production expense rate (expense per boe) for United States was lower primarily due to the disposition of higher cost non-core assets in Wyoming. The International expense rate decreased in the year of 2017 primarily due to an increase in sales volumes in E.G. and Libya, combined with lower maintenance costs in E.G.

($ per boe)	2017		2016	
Production Expense Rate	**Expense**	**Rate**	**Expense**	**Rate**
United States	$ 476	$ 5.57	$ 486	$ 5.96
International	$ 239	$ 4.51	$ 234	$ 5.26

Marketing costs decreased $77 million in 2017 from the prior year, consistent with the decrease in marketing revenues discussed above.

Shipping, handling, and other operating expenses decreased $53 million compared to 2016 which included the termination payment of our Gulf of Mexico deepwater drilling commitment in 2016.

Exploration expenses increased $86 million in 2017 versus the comparable 2016 period, due primarily to charges taken as a result of lower forecasted long-term commodity prices and the anticipated sales of certain non-core properties in our International segment. In 2017, we recorded non-cash charges of $159 million comprised of $95 million in unproved property impairments in our International segment and $64 million dry well costs related to our Diaba License G4-223 in the Republic of Gabon. Additionally, our decision not to develop the Tchicuate offshore Block in the Republic of Gabon resulted in an increase to exploration expenses of $43 million during 2017. Unproved property impairments during 2016 primarily consist of non-cash charges related to our decision to not drill our remaining Gulf of Mexico leases.

The following table summarizes the components of exploration expenses:

	Year Ended December 31,	
(In millions)	**2017**	**2016**
Exploration Expenses		
Unproved property impairments	$ 246	$ 195
Dry well costs	77	25
Geological and geophysical	25	5
Other	61	98
Total exploration expenses	$ 409	$ 323

Exploration expense are also discussed in Item 8. Financial Statements and Supplementary Data - Note 11 to the consolidated financial statements.

Depreciation, depletion and amortization increased $216 million in 2017 from the prior year primarily as a result of an increase of $176 million in the United States due to a 5% increase in net sales volumes, and an increase in the DD&A rates within our U.S. resource plays. Also contributing to this higher expense was an increase of $52 million in our International segment resulting from increased sales volumes due to the completion and start-up of our E.G. Alba field compression project in mid-2016, and the resumption of sales volumes and production in Libya. 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 (expense per boe), which is impacted by field-level changes in sales volumes, reserves and capitalized costs, can also cause changes to our DD&A. The DD&A rate for United States increased primarily due to the sales volume mix between our U.S. resource plays, and the outside-operated Gunflint field achieving first production in mid-2016. Also contributing to the increase was a reduction to the Eagle Ford proved developed reserve base in the fourth quarter of 2016. The DD&A rate for our International segment remained relatively consistent with the 2016 rate. The following table provides DD&A rates for each segment.

($ per boe)	**2017**	**2016**
DD&A Rate		
United States	$ 23.51	$ 22.49
International	$ 6.19	$ 6.21

Impairments increased $162 million in 2017 from the comparable 2016 period. This increase was primarily consisting of $136 million of proved property impairments in certain non-core properties in our International segment as a result of our anticipated sales and lower forecasted long-term commodity prices. Additionally, included in proved property impairments was $89 million in 2017 and $67 million in 2016, both relating to lower forecasted commodity prices in conventional properties in Oklahoma and the Gulf of Mexico. See Item 8. Financial Statements and Supplementary Data - **Note 11** to the consolidated financial statement for additional detail.

Taxes other than income includes production, severance and ad valorem taxes, primarily in the U.S., which tend to increase or decrease in relation to revenue and sales volumes. Taxes other than income increased $32 million in the current year as a result of increased revenue and sales volumes, and due to a reserve being established for non-income tax examinations relating to open tax years.

The following table summarizes the components of taxes other than income:

	Year Ended December 31,	
(In millions)	**2017**	**2016**
Taxes other than income		
Production and severance	$ 121	$ 91
Ad valorem	13	23
Other	49	37
Total taxes other than income	$ 183	$ 151

Net interest and other decreased $62 million during 2017 primarily as a result of the termination of our forward starting interest rate swaps, which resulted in a gain of $46 million. Additionally, during 2017 we reduced total long-term debt by approximately $1.75 billion which resulted in a reduction to our net interest and other. The components of net interest and other are detailed in Item 8. Financial Statements and Supplementary Data - **Note 16** to the consolidated financial statements.

Loss on early extinguishment of debt increased $51 million in 2017 primarily due to make-whole call provisions of $46 million paid upon the redemption of $1.76 billion in senior unsecured notes. See Item 8. Financial Statements and Supplementary Data - **Note 16** to the consolidated financial statements for further detail.

Other net periodic benefit costs decreased $83 million primarily due to reduced pension settlement charges of $32 million in 2017 compared to $103 million in 2016.

Provision (benefit) for income taxes reflects an effective tax rate from continuing operations of 83% and 79% for 2017 and 2016. In 2017, our tax expense was primarily a result of our full valuation allowance on our net federal deferred tax assets throughout 2017 and the effects of our foreign operations. See Item 8. Financial Statements and Supplementary Data - **Note 8** to the consolidated financial statements for a discussion of the effective income tax rate.

Discontinued operations are presented net of tax. See Item 8. Financial Statements and Supplementary Data - **Note 5** to the consolidated financial statements for financial information concerning our discontinued operations.

Segment Results: 2017 compared to 2016

Segment Income (Loss)

Segment income (loss) represents income (loss) from continuing operations excluding certain items not allocated to 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. Gains or losses on dispositions, certain impairments, 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 (loss) to net income (loss):

(In millions)	Year Ended December 31, 2017	2016
United States	$ (148)	$ (415)
International	374	228
Segment income (loss)	226	(187)
Items not allocated to segments, net of income taxes[a]	(1,056)	(1,900)
Income (loss) from continuing operations	(830)	(2,087)
Income (loss) from discontinued operations[b]	(4,893)	(53)
Net income (loss)	$ (5,723)	$ (2,140)

[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.

[b] We sold our Canadian business in the second quarter of 2017. The Canadian business is reflected as discontinued operations in all periods presented.

United States segment loss decreased $267 million in 2017 compared to 2016 primarily due to higher price realizations and higher sales volumes. Partially offsetting this revenue increase was an increase in DD&A and a decrease in the income tax benefit, as we did not realize a tax benefit on any net federal deferred tax assets generated in 2017 due to the full valuation allowance on net federal deferred tax assets in the prior year.

International segment income increased $146 million in 2017 compared to 2016 primarily due to higher price realizations, and an increase in sales volumes in E.G. and Libya. This was partially offset by an increase in DD&A and income tax expense as a result of the increase in sales volumes.

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 2018, we experienced an increase in operating cash flows primarily due to improvements in the commodity price environment with increased consolidated average crude oil and condensate price realizations of over 25% to $63.32, and an increase to net sales volumes of 11% to 420 mboed.

During 2018 we continued our cash flow growth with highlights that include:

- Cash and cash equivalents increased approximately $900 million to $1.5 billion at December 31, 2018.
- Cash provided by operating activities from continuing operations increased by 63%, compared to the same period last year, to $3,234 million.
- Used this additional cash provided by operating activities to return capital to shareholders by executing $700 million of share repurchases.
- Received $750 million in remaining proceeds from the sale of our Canadian business and $450 million in proceeds from the sale of our Libya subsidiary.
- Additionally these divestiture proceeds were used to capture additional acreage in our resource play leasing and exploration program of $369 million.

At December 31, 2018, we had approximately $4.9 billion of liquidity consisting of $1.5 billion in cash and cash equivalents and $3.4 billion available under our revolving credit facility. Additionally, during 2018 we extended the maturity date of our Credit Facility from May 28, 2021, to May 28, 2022. As previously discussed in our Outlook section, we are targeting a $2.6 billion Capital Budget for 2019. 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 throughout the different commodity price cycles. We will continue to evaluate the commodity price environment and our spending throughout 2019.

Cash Flows

The following table presents sources and uses of cash and cash equivalents from continuing operations for 2018, 2017 and 2016:

(In millions)	Year Ended December 31, 2018	2017	2016
Sources of cash and cash equivalents			
Operating activities - continuing operations	$ 3,234	$ 1,988	$ 901
Disposal of assets, net of cash transferred to the buyer	1,264	1,787	1,219
Common stock issuance	—	—	1,236
Borrowings	—	988	—
Other	93	68	56
Total sources of cash and cash equivalents	$ 4,591	$ 4,831	$ 3,412
Uses of cash and cash equivalents			
Additions to property, plant and equipment	$ (2,753)	$ (1,974)	$ (1,204)
Additions to other assets	(26)	(25)	—
Acquisitions, net of cash acquired	(25)	(1,891)	(902)
Purchases of common stock	(713)	(11)	(6)
Debt repayments	—	(2,764)	(1)
Debt extinguishment costs	—	(46)	—
Dividends paid	(169)	(170)	(162)
Other	(6)	(5)	(6)
Total uses of cash and cash equivalents	$ (3,692)	$ (6,886)	$ (2,281)

Cash flows generated from operating activities in 2018 were 63% higher as both commodity price realizations and net sales volumes improved compared to 2017. Consolidated average crude oil and condensate price realizations increased by over 25% and net sales volumes increased 11% during 2018 as compared to 2017.

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. Proceeds from the disposals of assets for 2017 is primarily the result of the disposal of our Canadian business, and in 2016 are primarily from the sale of our Wyoming upstream and midstream assets, as well as the sale of certain other non-operated CO_2 and waterflood assets in West Texas and New Mexico. Disposition transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 5 to the consolidated financial statements.

Issuance of common stock reflects net proceeds received in 2016 from our public sale of common stock.

Borrowings in 2017 are a result of the issuance of $1 billion of 4.4% senior unsecured notes due in 2027. Financing transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – Note 16 to the consolidated financial statements for additional information.

Additions to property, plant and equipment reflect a significant use of cash and cash equivalents. The following table shows capital expenditures related to continuing operations by segment and reconciles to additions to property, plant and equipment as presented in the consolidated statements of cash flows:

(In millions)	Year Ended December 31, 2018	2017	2016
United States [(a)]	$ 2,620	$ 2,081	$ 936
International	39	42	82
Corporate	26	27	18
Total capital expenditures	2,685	2,150	1,036
Change in capital expenditure accrual	68	(176)	168
Total use of cash and cash equivalents for property, plant and equipment	$ 2,753	$ 1,974	$ 1,204

[(a)] 2018 capital expenditures includes 1,800 net acres in New Mexico for $105 million acquired from the Bureau of Land Management lease sale.

Additions to other assets relates to deposits on our resource play leasing and exploration program. During 2018 our resource play leasing and exploration capital expenditures totaled $369 million, largely including costs within property, plant and equipment, other assets and acquisitions. These expenditures were more than fully funded through the divestiture proceeds received in 2018.

During 2017, we closed on multiple Permian basin acquisitions for approximately $1.9 billion with cash on hand. Additionally, during 2016, we closed the Oklahoma STACK acquisition for a purchase price of $904 million, net of cash acquired. See Item 8. Financial Statements and Supplementary Data – **Note 4** to the consolidated financial statements for further information concerning acquisitions.

In 2018, we acquired 36 million common shares at a cost of $700 million, excluding transaction fees and commissions, under our share repurchase program. Shares purchased were held as treasury stock. See **Note 23** to the consolidated financial statements for additional information.

In December 2017, we redeemed $1 billion of 5.125% municipal revenue bonds due in 2037 in a refunding transaction. Additionally, during the third quarter of 2017, we used the net proceeds of the borrowing disclosed above plus existing cash on hand to redeem $1.76 billion in senior unsecured notes resulting in a recognized loss on early extinguishment of debt of $46 million, primarily due to make-whole call provisions. Financing transactions are discussed in further detail in Item 8. Financial Statements and Supplementary Data – **Note 16** to the consolidated financial statements for additional information.

During 2018, 2017 and 2016, the Board of Directors approved a $0.05 per share quarterly dividend. See Capital Requirements below for additional information about the fourth quarter 2018 dividend.

Liquidity and Capital Resources

In October 2018, we extended the maturity date of our Credit Facility from May 28, 2021, to May 28, 2022. Fees on the unused commitment to the lenders, as well as the borrowing options under the Credit Facility, remain unaffected by the term extension. We retain the ability to request two one-year extensions and an option to increase the commitment amount by up to an additional $107 million, subject to the consent of any increasing lenders. The sub-facilities for swing-line loans and letters of credit remain unchanged allowing up to an aggregate amount of $100 million and $500 million, respectively.

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, 2018, we had approximately $4.9 billion of liquidity consisting of $1.5 billion in cash and cash equivalents and $3.4 billion available under our revolving Credit Facility. Our working capital requirements are supported by these sources and we may 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 budgets, 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, 2018 are: Standard & Poor's Ratings Services BBB- (positive); Fitch Ratings BBB (stable); and Moody's Investor Services, Inc. Ba1 (positive). 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 further downgrade in our credit ratings could affect us.

Additionally, in December of 2017, we redeemed $1 billion of 5.125% municipal revenue bonds due in 2037 in a refunding transaction that preserved our ability to remarket up to $1 billion of tax-exempt municipal bonds prior to 2037. 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, 2018, we had no borrowings against our revolving credit facility.

At December 31, 2018, we had $5.5 billion in long-term debt outstanding, with our next debt maturity in the amount of $600 million due in 2020. 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.

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

We entered into an agreement to sell our subsidiary, Marathon Oil KDV B.V., which holds 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 December 31, 2018 and 32% at December 31, 2017.

(In millions)	2018	2017
Long-term debt due within one year	$ —	$ —
Long-term debt	5,499	5,494
Total debt	$ 5,499	$ 5,494
Equity	$ 12,128	$ 11,708
Calculation		
Total debt	$ 5,499	$ 5,494
Total debt plus equity (total capitalization)	$ 17,627	$ 17,202
Debt-to-capital ratio	31%	32%

Capital Requirements

Capital Spending

Our approved Capital Budget for 2019 is $2.6 billion. Additional details were previously discussed in **Outlook**.

Share Repurchase Program

In 2018, we acquired 36 million common shares at a cost of $700 million under our share repurchase program. The remaining share repurchase authorization as of December 31, 2018 is $800 million.

Other Expected Cash Outflows

On January 30, 2019, our Board of Directors approved a dividend of $0.05 per share for the fourth quarter of 2018. The dividend is payable on March 11, 2019 to shareholders of record on February 20, 2019.

We plan to make contributions of up to $50 million to our funded pension plans during 2019. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $5 million and $18 million in 2019.

Contractual Cash Obligations

The table below provides aggregated information on our consolidated obligations to make future payments under existing contracts as of December 31, 2018.

(In millions)	Total	2019	2020-2021	2022-2023	Later Years
Short and long-term debt (includes interest)[(a)]	$ 8,521	$ 256	$ 1,087	$ 1,680	$ 5,498
Lease obligations	217	62	89	17	49
Purchase obligations:					
Oil and gas activities[(b)]	69	58	1	1	9
Service and materials contracts[(c)]	122	83	39	—	—
Transportation and related contracts	1,355	327	330	229	469
Other [(d)]	39	18	21	—	—
Total purchase obligations	1,585	486	391	230	478
Other long-term liabilities reported in the consolidated balance sheet[(e)]	548	149	65	56	278
Total contractual cash obligations[(f)]	$ 10,871	$ 953	$ 1,632	$ 1,983	$ 6,303

(a) Includes anticipated cash payments for interest of $256 million for 2019, $487 million for 2020-2021, $443 million for 2022-2023 and $1,798 million for the remaining years for a total of $2,984 million.

(b) 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.

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

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

(e) 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.

(f) This table does not include the estimated discounted liability for dismantlement, abandonment and restoration costs of oil and gas properties of $1,145 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, 2018, 2017 and 2016 aggregated $52 million, $89 million and $166 million. Most of the letters of credit are in support of obligations recorded in the consolidated balance sheet. For example, they are issued to counterparties to support firm transportation agreements and future abandonment liabilities.

In 2018, we signed an agreement with a 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, 2018 project costs incurred totaled $45 million, primarily for land acquisition costs. The five-year lease term will commence once construction is substantially complete and the new Houston office is able to be occupied. 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; remarket the property to an unrelated third party. As of December 31, 2018 we have recorded this agreement as an operating lease, see Item 8. Financial Statements and Supplementary Data – **Note 24** to the consolidated financial statements for further information on operating leases.

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

We have incurred and may continue to incur substantial 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 reflected in 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.

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. 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 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, production history and continual reassessment of the viability of production 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 2018 SEC pricing for certain benchmark prices:

		2018 SEC Pricing
WTI Crude oil (per bbl)	$	65.56
Henry Hub natural gas (per mmbtu)	$	3.05
Brent crude oil (per bbl)	$	72.70
Mont Belvieu NGLs (per bbl)	$	26.63

When determining the December 31, 2018 proved reserves for each property, the benchmark prices listed above were adjusted using price differentials that account for property-specific quality and location differences.

Estimates of future cash flows associated with proved reserves are based on actual costs of developing and producing proved reserves at the end of the year. If annual SEC crude oil benchmark prices (see table above) were to decrease to approximately $45 per bbl, or 30% below average prices used to estimate 2018 proved reserves, we would not expect price related reserve revisions to have a material impact on proved reserve volumes. 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 2018 proved reserves based on 2018 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	$ (1.85)	$ 202	$ 2.27	$ (246)
International	$ (0.40)	$ 18	$ 0.49	$ (22)

Asset Retirement Obligations

We have material legal, regulatory and contractual obligations to remove and dismantle long-lived assets and to restore land or seabed at the end of oil and gas production operations. A liability equal to the fair value of such obligations and a corresponding capitalized asset retirement cost are recognized on the balance sheet in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be made. The capitalized asset retirement cost is depreciated using the units-of-production method or the straight line method (dependent on the underlying asset) and the discounted liability is accreted over the period until the obligation is satisfied, the impacts of which are recognized as DD&A in the consolidated statements of income. In many cases, the satisfaction and subsequent discharge of these liabilities is projected to occur many years, or even decades, into the future. Furthermore, the legal, regulatory and contractual requirements often do not provide specific guidance regarding removal practices and the criteria that must be fulfilled when the removal and/or restoration event actually occurs.

Estimates of retirement costs are developed for each property based on numerous factors, such as the scope of the dismantlement, timing of settlement, interpretation of legal, regulatory and contractual requirements, type of production and processing structures, depth of water (if applicable), reservoir characteristics, depth of the reservoir, market demand for equipment, currently available dismantlement and restoration procedures and consultations with construction and engineering professionals. Currency exchange rates, inflation rates and credit-adjusted-risk-free interest rates are then applied to estimate the fair values of the obligations. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related asset balance or income statement, as appropriate. Changes in estimated asset retirement obligations for late life assets could result in impairment or in the recognition of income. During 2018 we made revisions to these estimates and reduced our recognized liability by $204 million. This downward revision was primarily due to the acceleration of our U.K. abandonment activities to capture favorable market conditions and lower estimated abandonment costs. See Item 8. Financial Statements and Supplementary Data – **Note 12** to the consolidated financial statements for disclosures regarding our asset retirement obligation estimates.

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 obligations that must be assessed, the number of underlying assumptions and the wide range of possible assumptions.

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 15** to the consolidated financial statements for disclosures regarding our fair value measurements.

Significant uses of fair value measurements include:

- impairment assessments of long-lived assets;
- impairment assessments of goodwill; and
- recorded value of derivative instruments.

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 2018 the anticipated sales of certain non-core proved properties in our International and United States segments triggered an assessment of certain of our long-lived assets related to oil and gas producing properties for impairment. We estimated the fair values using a market approach, based upon anticipated sales proceeds less costs to sell, and recognized impairments. As of December 31, 2018 our estimated undiscounted cash flows relating to our remaining long-lived assets significantly exceeded their carrying values in our core assets. Long-lived assets most at risk for future impairment had an estimated carrying value of less than $50 million. See Item 8. Financial Statements and Supplementary Data **Note 11** and **Note 15** to the consolidated financial statements for discussion of impairments recorded in 2018, 2017 and 2016 and the related fair value measurements.

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.

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, 2018, our consolidated balance sheet included goodwill of $97 million. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. 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 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 2018, 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. 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 13** 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 14** 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**.

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, 2018, we reflect a valuation allowance in our consolidated balance sheet of $749 million against our gross deferred tax assets of $2.0 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 $472 million in 2018 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.

Of the assumptions used to measure obligations and estimated annual net periodic benefit cost as of December 31, 2018 the discount rate has the most significant effect on the periodic benefit cost reported for the plans. The hypothetical impacts of a 0.25% change in the discount rates of 4.26% for our U.S. pension plans and 4.09% for our other U.S. postretirement benefit plans is summarized in the table below:

	Impact of a 0.25% Increase in Discount Rate		Impact of a 0.25% Decrease in Discount Rate	
(In millions)	**Obligation**	**Expense**	**Obligation**	**Expense**
U.S. pension plans	$ (3)	$ —	$ 3	$ —
Other U.S. postretirement benefit plans	$ (1)	$ —	$ 1	$ —

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. Decreasing the 6.50% asset rate of return assumption by 0.25% would not have a significant impact on our defined benefit pension expense.

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 18** 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 commodity price 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 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 14** and **Note 15** 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 2018, 2017 and 2016 were impacted by crude oil and natural gas derivatives related to a portion of our forecasted United States sales.

As of December 31, 2018, we had various open commodity derivatives related to crude oil and natural gas with a net asset position of $127 million. Based on the December 31, 2018, published NYMEX WTI and Henry Hub futures prices, a hypothetical 10% change (per bbl for crude oil and per MMBtu for natural gas) increases (decreases) the fair values of our net commodity derivative open positions as follows:

(In millions)	Hypothetical Price Increase of 10%	Hypothetical Price Decrease of 10%
Crude oil derivatives	$ (30)	$ 19
Natural gas derivatives	(1)	1
Total	$ (31)	$ 20

Interest Rate Risk

At December 31, 2018, 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.

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, 2018.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The 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.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 21, 2019

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, 2018	2017	2016
Revenues and other income:			
Revenues from contracts with customers	$ 5,902	$ 4,247	$ 2,996
Net gain (loss) on commodity derivatives	(14)	(36)	(66)
Marketing revenues	—	162	240
Income from equity method investments	225	256	175
Net gain (loss) on disposal of assets	319	58	389
Other income	150	78	53
Total revenues and other income	6,582	4,765	3,787
Costs and expenses:			
Production	842	716	720
Marketing, including purchases from related parties	—	168	245
Shipping, handling and other operating	575	431	484
Exploration	289	409	323
Depreciation, depletion and amortization	2,441	2,372	2,156
Impairments	75	229	67
Taxes other than income	299	183	151
General and administrative	394	371	371
Total costs and expenses	4,915	4,879	4,517
Income (loss) from operations	1,667	(114)	(730)
Net interest and other	(226)	(270)	(332)
Other net periodic benefit costs	(14)	(19)	(102)
Loss on early extinguishment of debt	—	(51)	—
Income (loss) from continuing operations before income taxes	1,427	(454)	(1,164)
Provision (benefit) for income taxes	331	376	923
Income (loss) from continuing operations	1,096	(830)	(2,087)
Income (loss) from discontinued operations	—	(4,893)	(53)
Net income (loss)	$ 1,096	$ (5,723)	$ (2,140)
Per basic share:			
Income (loss) from continuing operations	$ 1.30	$ (0.97)	$ (2.55)
Income (loss) from discontinued operations	$ —	$ (5.76)	$ (0.06)
Net income (loss)	$ 1.30	$ (6.73)	$ (2.61)
Per diluted share:			
Income (loss) from continuing operations	$ 1.29	$ (0.97)	$ (2.55)
Income (loss) from discontinued operations	$ —	$ (5.76)	$ (0.06)
Net income (loss)	$ 1.29	$ (6.73)	$ (2.61)
Weighted average common shares outstanding:			
Basic	846	850	819
Diluted	847	850	819

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, 2018	2017	2016
Net income (loss)	$ 1,096	$ (5,723)	$ (2,140)
Other comprehensive income (loss)			
Postretirement and postemployment plans:			
Change in actuarial loss and other	117	21	16
Income tax provision (benefit)	4	7	(4)
Postretirement and postemployment plans, net of tax	121	28	12
Derivative hedges:			
Net unrecognized gain (loss)	—	(13)	61
Reclassification of gains on terminated derivative hedges	—	(47)	—
Income tax provision (benefit)	—	21	(22)
Derivative hedges, net of tax	—	(39)	39
Foreign currency hedges:			
Net recognized loss reclassified to discontinued operations	—	34	—
Income tax provision (benefit)	—	(4)	—
Foreign currency hedges, net of tax	—	30	—
Other, net of tax	4	2	1
Other comprehensive income (loss)	125	21	52
Comprehensive income (loss)	$ 1,221	$ (5,702)	$ (2,088)

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

MARATHON OIL CORPORATION
Consolidated Balance Sheets

(In millions, except par values and share amounts)	December 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 1,462	$ 563
Receivables, less reserve of $11 and $12	1,079	1,082
Notes receivable	—	748
Inventories	96	126
Other current assets	257	36
Current assets held for sale	27	11
Total current assets	2,921	2,566
Equity method investments	745	847
Property, plant and equipment, less accumulated depreciation, depletion and amortization of $21,830 and $21,564	16,804	17,665
Goodwill	97	115
Other noncurrent assets	723	764
Noncurrent assets held for sale	31	55
Total assets	$ 21,321	$ 22,012
Liabilities		
Current liabilities:		
Accounts payable	$ 1,320	$ 1,395
Payroll and benefits payable	154	108
Accrued taxes	181	177
Other current liabilities	170	288
Current liabilities held for sale	7	—
Total current liabilities	1,832	1,968
Long-term debt	5,499	5,494
Deferred tax liabilities	199	833
Defined benefit postretirement plan obligations	195	362
Asset retirement obligations	1,081	1,428
Deferred credits and other liabilities	279	217
Noncurrent liabilities held for sale	108	2
Total liabilities	9,193	10,304
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 and 937 million shares (par value $1 per share, 1.925 billion shares authorized at December 31, 2018 and 1.1 billion shares authorized at December 31, 2017)	937	937
Held in treasury, at cost – 118 million shares and 87 million shares	(3,816)	(3,325)
Additional paid-in capital	7,238	7,379
Retained earnings	7,706	6,779
Accumulated other comprehensive income (loss)	63	(62)
Total stockholders' equity	12,128	11,708
Total liabilities and stockholders' equity	$ 21,321	$ 22,012

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

MARATHON OIL CORPORATION
Consolidated Statements of Cash Flows

	Year Ended December 31,		
(In millions)	**2018**	**2017**	**2016**
Increase (decrease) in cash and cash equivalents			
Operating activities:			
Net income (loss)	$ 1,096	$ (5,723)	$ (2,140)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Discontinued operations	—	4,893	53
Depreciation, depletion and amortization	2,441	2,372	2,156
Impairments	75	229	67
Exploratory dry well costs and unproved property impairments	255	323	220
Net (gain) loss on disposal of assets	(319)	(58)	(389)
Deferred income taxes	52	(61)	828
Net (gain) loss on derivative instruments	14	36	66
Net settlements of derivative instruments	(281)	45	44
Pension and other post retirement benefits, net	(65)	(46)	(3)
Stock-based compensation	53	49	51
Equity method investments, net	45	20	17
Changes in:			
Current receivables	(133)	(334)	67
Inventories	(1)	10	64
Current accounts payable and accrued liabilities	179	297	(137)
Other current assets and liabilities	(22)	1	33
All other operating, net	(155)	(65)	(96)
Net cash provided by operating activities from continuing operations	3,234	1,988	901
Investing activities:			
Additions to property, plant and equipment	(2,753)	(1,974)	(1,204)
Additions to other assets	(26)	(25)	—
Acquisitions, net of cash acquired	(25)	(1,891)	(902)
Disposal of assets, net of cash transferred to the buyer	1,264	1,787	1,219
Equity method investments - return of capital	57	64	55
All other investing, net	13	(5)	(1)
Net cash used in investing activities from continuing operations	(1,470)	(2,044)	(833)
Financing activities:			
Borrowings	—	988	—
Debt repayments	—	(2,764)	(1)
Debt extinguishment costs	—	(46)	—
Common stock issuance	—	—	1,236
Purchases of common stock	(713)	(11)	(6)
Dividends paid	(169)	(170)	(162)
All other financing, net	23	—	1
Net cash provided by (used in) financing activities	(859)	(2,003)	1,068
Net increase in cash and cash equivalents of discontinued operations (Note 5)	—	130	238
Effect of exchange rate on cash and cash equivalents	(2)	4	(3)
Cash held for sale	(4)	—	(2)
Net increase (decrease) in cash and cash equivalents	899	(1,925)	1,369
Cash and cash equivalents at beginning of period	563	2,488	1,119
Cash and cash equivalents at end of period	$ 1,462	$ 563	$ 2,488

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

MARATHON OIL CORPORATION
Consolidated Statements of Stockholders' Equity

	Total Equity of Marathon Oil Stockholders						
(In millions)	Preferred Stock	Common Stock	Treasury Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
December 31, 2015 Balance	$ —	$ 770	$ (3,554)	$ 6,498	$ 14,974	$ (135)	$ 18,553
Shares issued - stock-based compensation	—	—	128	(86)	—	—	42
Shares repurchased	—	—	(5)	—	—	—	(5)
Stock-based compensation	—	—	—	(35)	—	—	(35)
Net loss	—	—	—	—	(2,140)	—	(2,140)
Other comprehensive income	—	—	—	—	—	52	52
Dividends paid ($0.20 per share)	—	—	—	—	(162)	—	(162)
Common stock issuance	—	167	—	1,069	—	—	1,236
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)
Common stock issuance	—	—	—	—	—	—	—
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

(Shares in millions)	Preferred Stock	Common Stock	Treasury Stock
December 31, 2015 Balance	—	770	93
Shares issued - stock-based compensation	—	—	(3)
Common stock issuance	—	167	—
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

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.

During the year, we renamed our United States E&P and International E&P segments to the United States and International segments. The characteristics and composition of these segments remained unchanged and there was no effect on previously reported segment information. See **Note 7** for further information on our reportable segments.

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 revenue 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. Differences in the basis of the investments and the separate net asset value of the investees, if any, are amortized into income over the remaining useful lives of the underlying assets, except for the excess related to goodwill.

Reclassifications – In the first quarter of 2018 we adopted the new Accounting Standards Codification ("ASC") Topic 606, Revenue from Contracts with Customers using the modified retrospective method. To conform the historical presentation to our current presentation, we reclassified gains/losses arising from our commodity derivatives out of the revenues from contracts with customers line into a separate line, net gain (loss) on commodity derivatives, on the consolidated statements of income. Additionally, in the first quarter of 2018 we adopted the new pension accounting standards update on a retrospective basis, and reclassified the required cost elements from general and administrative expense into production expense, exploration expense, and other net periodic benefit costs. See **Note 2** for further discussion of the adoption of these accounting standards.

Additionally, we have reclassified certain prior year amounts between operating cash flow categories to present it on a basis comparable with the current year's presentation with no impact on net cash provided by operating activities.

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. Assets and liabilities are presented as held for sale in the historical periods in the consolidated balance sheets. 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 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 – We recognize revenue at an amount that reflects the consideration to which we believe we are entitled in exchange for transferring goods and/or services to a customer. In the lower 48 states of the U.S., production volumes of crude oil and condensate, NGLs and natural gas are generally sold immediately and transported to market. In international locations, liquid hydrocarbon production volumes may be stored as inventory and sold at a later time.

See **Note 6** for further discussion of the revenue recognition accounting policies.

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 joint interest owners in properties we operate or from purchasers of commodities, both of which are recorded at 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.

Notes receivable – At closing of the sale of our Canadian business in 2017 we received two notes receivable for a combined $750 million, we received these proceeds in the first quarter of 2018. Both notes receivable were initially recorded at fair value and were reported at amortized cost. These notes receivable were evaluated for collectability on an individual basis each reporting period, based on the financial condition of the debtor. See **Note 5** for additional discussion.

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, foreign currency 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, foreign currency 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 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 effective portion of changes in the fair value of a qualifying cash flow hedge are recorded in other comprehensive income until the hedged item is reclassified to net income when the underlying forecasted transaction is recognized in net income. Ineffective portions of a cash flow hedge’s change in fair value are recognized currently within net interest and other on the consolidated statements of income. However, if it is determined that the likelihood of the original forecasted transaction occurring is no longer probable, the entire accumulated gain or loss recognized in other comprehensive income is immediately reclassified into 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 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. If significant transfers occur, they would be disclosed in **Note 15** to the consolidated financial statements.

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	10 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.

Major maintenance activities – Costs for planned major maintenance are expensed in the period incurred and can include the costs of contractor repair services, materials and supplies, equipment rentals and our labor costs.

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 and seabed, including those leased. Estimates of these costs are developed for each property based on the type of production facilities and equipment, depth of water, 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 and common stock units is determined based on the market value of our common stock on the date of grant. Unearned stock-based compensation is charged to stockholders’ equity when restricted stock awards are granted.

The fair value of our 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.

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

Lease accounting standard

In February 2016, the FASB issued a new lease accounting standard, which requires lessees to recognize most leases, including operating leases, on the balance sheet as a right of use asset and lease liability. Short-term leases can continue being accounted for off balance sheet based on a policy election. This standard 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. This standard is effective for us in the first quarter of 2019 and shall be applied using a modified retrospective approach at the beginning of the earliest period presented in the financial statements. Early adoption is permitted.

In July 2018, the FASB issued a new transition option that allows entities to adopt the new lease accounting standard using the modified retrospective transition method by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption rather than in the earliest period presented. We elected this new transition option and continue to apply the legacy guidance in ASC 840, Leases, including its disclosure requirements, in the comparative periods presented in the year of adoption.

We will adopt the new standard in the first quarter of 2019 and will recognize a right of use asset and lease liability on the adoption date. We will apply practical expedients provided in the standard that allow, among others, not to reassess contracts that commenced or expired prior to the effective date. We also elected a policy not to recognize right of use assets and lease liabilities related to short-term leases.

To facilitate the adoption of this standard, we completed the installation and configuration of a software system in January 2019. While we continue to evaluate our contracts and associated data for compliance with the new standard, we believe the adoption of this standard as of January 1, 2019 will result in the recognition of a right of use asset and related lease liability, on our consolidated balance sheet, between $160 million to $210 million.

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 is effective for us in the first quarter of 2019. The amendment mandates modified retrospective adoption when accounting for hedge relationships in effect as of the adoption date. None of our derivative instruments are currently designated as hedges; as a result we do not expect the adoption of this standard to have a significant impact on our consolidated results of operations, financial position or cash flows.

Goodwill standard

In January 2017, the FASB issued a new accounting standards update that eliminates the requirement to calculate the implied fair value of the goodwill (Step 2 of goodwill impairment test under the current guidance) to measure a goodwill impairment charge. We anticipate the standard to require entities to record an impairment charge based on the excess of a reporting unit’s carrying amount over its fair value (measure the charge based on Step 1 under the current guidance). This standard is effective for us in the first quarter of 2020 and shall be applied on a prospective basis. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. We plan to adopt the standard on a prospective basis, and do not expect a material impact on our consolidated results of operations, financial position or cash flows for prior periods.

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. Early adoption is permitted starting January 2019. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

Recently Adopted

Revenue recognition standard

On January 1, 2018, we adopted the new ASC Topic 606, Revenue from Contracts with Customers and all the related amendments ("new revenue standard") using the modified retrospective method. We evaluated the effect of transition by applying the provisions of the new revenue standard to contracts with remaining obligations as of January 1, 2018. No cumulative adjustment to retained earnings was necessary as a result of adopting this standard.

Results for reporting periods beginning after January 1, 2018 are presented under the new revenue standard, while prior period amounts are not adjusted and continue to be reported in accordance with our historic accounting policies. The primary change relates to the presentation of marketing revenues and marketing expenses from the historical gross presentation to the current net presentation, included within revenues from contracts with customers, for a portion of our international contracts.

We concluded that the adoption of the new revenue standard did not result in any significant changes to our consolidated balance sheet or statement of cash flows. The following tables summarize the impacts of adopting the new revenue standard on our consolidated income statement for the year ended December 31, 2018.

	Year Ended December 31, 2018		
(In millions)	As reported	Adjustments	Presentation without adoption of ASC Topic 606
Revenues and other income:			
Revenues from contracts with customers	$ 5,902	$ (12)	$ 5,890
Marketing revenues	—	159	159
Other income	150	(5)	145
Costs and expenses:			
Marketing, including purchases from related parties	$ —	$ 158	$ 158
Shipping, handling and other operating	575	(16)	559

Pension accounting standard

In the first quarter of 2018, we adopted the new accounting standards update that changes how employers that sponsor defined pension and/or other postretirement benefit plans present the net periodic benefit cost in the income statement. As a result, employers are required to present the service cost component of net periodic benefit cost in the same income statement line item(s) as other employee compensation costs arising from services rendered during the period. We adopted this standard on a retrospective basis, and reclassified the required cost elements from general and administrative expense into production expense, exploration expense, and other net periodic benefit costs. The adoption of this standard did not have a significant impact on our consolidated balance sheet or statement of cash flows. The following tables summarize the impacts of adopting this standard on our historical consolidated income statement for the years ended December 31, 2017 and 2016.

	Year Ended December 31, 2017		
(In millions)	Previously Reported	As reclassified	Effect of Change Higher/(Lower)
Production	$ 706	$ 716	$ 10
Exploration	409	409	—
General and administrative	400	371	(29)
Income (loss) from operations	(133)	(114)	19
Other net periodic benefit costs[(a)]	—	(19)	(19)

	Year Ended December 31, 2016		
(In millions)	Previously Reported	As reclassified	Effect of Change Higher/(Lower)
Production	$ 712	$ 720	$ 8
Exploration	323	323	—
General and administrative	481	371	(110)
Income (loss) from operations	(832)	(730)	102
Other net periodic benefit costs[(a)]	—	(102)	(102)

[(a)] Includes net settlement loss and other net periodic benefit costs, excluding service costs (See **Note 18**).

Classification in the statement of cash flows

In August 2016, the FASB issued a new accounting standards update which seeks to reduce the existing diversity in practice in how certain transactions are classified in the statement of cash flows. This standard was effective for us in the first quarter of 2018, and was applied retrospectively. Adoption of this standard did not have a significant impact on our consolidated statements of cash flows.

Presentation of restricted cash in the statement of cash flows

In November 2016, the FASB issued a new accounting standards update that requires entities to show the changes in the total of cash, cash equivalents and restricted cash in the statement of cash flows. As a result, we no longer present transfers between cash and cash equivalents and restricted cash in the statement of cash flows. When cash, cash equivalents, and restricted cash are presented in more than one line item on the balance sheet, the standard requires a reconciliation of the totals in the statement of cash flows to the related captions in the balance sheet. This reconciliation can be presented either on the face of the statement of cash flows or in the notes to the financial statements. This standard was effective for us in the first quarter of 2018, and was applied retrospectively. Adoption of this standard did not have a significant impact on our consolidated statements of cash flows.

Accounting for sale or transfer of nonfinancial assets

In February 2017, the FASB issued a new accounting standards update that clarifies the accounting for the sale or transfer of nonfinancial assets and in substance nonfinancial assets to noncustomers, including partial sales. The standard also clarifies that the derecognition of all businesses (except those related to conveyances of oil and gas mineral rights or contracts with customers) should be accounted for in accordance with the derecognition and deconsolidation guidance in Subtopic 810-10. This standard was effective for us in the first quarter of 2018, and was applied using the modified retrospective approach. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Definition of a business

In January 2017, the FASB issued a new accounting standards update that changes the definition of a business to assist entities with evaluating when a set of transferred assets and activities constitutes a business. The guidance requires us to evaluate if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets; if so, the set of transferred assets and activities would not represent a business. The guidance also requires a business to include at least one substantive process and narrows the definition of outputs by more closely aligning it with how outputs are described in the new revenue guidance. This standard was effective for us in the first quarter of 2018, and was applied prospectively. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Financial instruments updates

In January 2016, the FASB issued an accounting standards update that addresses certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. We adopted this standard in the first quarter of 2018. 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 per share assumes exercise of stock options in all periods, provided the effect is not antidilutive. The per share calculations below exclude 6 million, 11 million and 13 million stock options in 2018, 2017 and 2016 that were antidilutive.

	Year Ended December 31,		
(In millions, except per share data)	2018	2017	2016
Income (loss) from continuing operations	$ 1,096	$ (830)	$ (2,087)
Income (loss) from discontinued operations	—	(4,893)	(53)
Net income (loss)	$ 1,096	$ (5,723)	$ (2,140)
Weighted average common shares outstanding	846	850	819
Effect of dilutive securities	1	—	—
Weighted average common shares, diluted	847	850	819
Per basic share:			
Income (loss) from continuing operations	$ 1.30	$ (0.97)	$ (2.55)
Income (loss) from discontinued operations	$ —	$ (5.76)	$ (0.06)
Net income (loss)	$ 1.30	$ (6.73)	$ (2.61)
Per diluted share:			
Income (loss) from continuing operations	$ 1.29	$ (0.97)	$ (2.55)
Income (loss) from discontinued operations	$ —	$ (5.76)	$ (0.06)
Net income (loss)	$ 1.29	$ (6.73)	$ (2.61)
Dividends per share	$ 0.20	$ 0.20	$ 0.20

4. Acquisitions

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, subject to post-closing adjustments. We 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.

2016 - United States Segment

On August 1, 2016, we closed on our acquisition of PayRock Energy Holdings, LLC ("PayRock"), a portfolio company of EnCap Investments, including approximately 61,000 net surface acres in the oil window of the Anadarko Basin STACK play in Oklahoma. The purchase price of $904 million, subject to closing adjustments, was paid with cash on hand. We accounted for this transaction as an asset acquisition, with a majority 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.

In the third quarter of 2017, we closed on the sale of certain conventional assets in Oklahoma for proceeds of $25 million, subject to closing adjustments, and recognized a pre-tax gain of $21 million.

In the third quarter of 2016, we entered into an agreement to sell certain non-operated CO2 and waterflood assets in West Texas and New Mexico. This sale closed during the fourth quarter for proceeds of $235 million, and a pre-tax gain of $63 million. During the third quarter 2016, we sold certain non-operated assets primarily in West Texas and New Mexico to multiple purchasers for combined proceeds of approximately $67 million, and recognized a total pre-tax gain of $55 million.

During the second quarter of 2016, we received proceeds of approximately $690 million related to sale of our Wyoming upstream and midstream assets and recorded a pre-tax gain of $266 million; with the remaining Wyoming asset sales closing in fourth quarter of 2016 for proceeds of $155 million, excluding closing adjustments and a pre-tax gain of $38 million.

In March and April 2016, we entered into separate agreements to sell our 10% working interest in the outside-operated Shenandoah discovery in the Gulf of Mexico, operated natural gas assets in the Piceance basin in Colorado and certain undeveloped acreage in West Texas for a combined total of approximately $80 million in proceeds. We closed on certain of the asset sales and recognized a net pre-tax loss on sale of $48 million in 2016, the remaining asset closed in 2017 with a net pre-tax gain on sale of $32 million.

International Segment

In the fourth quarter of 2018, we entered into an agreement to sell our subsidiary, Marathon Oil KDV B.V., which holds our 15% non-operated interest in the Atrush block in Kurdistan for proceeds of $63 million, before closing adjustments. This property is classified as held for sale in the consolidated balance sheet at December 31, 2018, with total assets of $58 million, total liabilities of $17 million. We expect the transaction to close in the first half of 2019.

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.

In the third quarter of 2017, we entered into separate agreements to sell certain non-core properties for combined proceeds of $53 million, before closing adjustments. We closed on one of the asset sales in the fourth quarter of 2017 and recognized no pre-tax gain or loss on sale. We closed on the remaining asset sale during the third quarter of 2018 for a pre-tax loss of $18 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:

	Year Ended December 31,		
(In millions)	**2018**	**2017**	**2016**
Total revenue and other income	$ —	$ 431	$ 863
Net gain (loss) on disposal of assets	—	(43)	—
Total revenues and other income	—	388	863
Costs and expenses:			
Production	—	254	601
Exploration	—	—	7
Depreciation, depletion and amortization	—	40	239
Impairments	—	6,636	—
Other	—	25	87
Total costs and expenses	—	6,955	934
Pretax income (loss) from discontinued operations	—	(6,567)	(71)
Provision (benefit) for income taxes	—	(1,674)	(18)
Income (loss) from discontinued operations	$ —	$ (4,893)	$ (53)

	Year Ended December 31,		
(In millions)	**2018**	**2017**	**2016**
Cash flow from discontinued operations:			
Operating activities	$ —	$ 141	$ 177
Investing activities	—	(13)	(41)
Changes in cash included in current assets held for sale	—	2	100
Net increase in cash and cash equivalents of discontinued operations	$ —	$ 130	$ 236

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 U.S. 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, 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 (In millions)	Year Ended December 31, 2018 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

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 arrangement and collective decisions of the joint parties. 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, in accordance with the new revenue standard, and such reimbursements will continue to not be recorded as revenues within the scope of the new revenue 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, and we do not purchase or otherwise obtain control of other working interest owners' share of production. 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, as defined in the new revenue standard, 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.

(In millions)	December 31, 2018	January 1, 2018
Receivables from contracts with customers, which are included in receivables, less reserves	$ 714	$ 811
Contract asset (liability)	$ (1)	$ —

The contract liability primarily relates to the advance consideration received from customers for crude oil sales and processing services in the U.K. A contract asset would represent crude oil delivered in the U.K. to a customer for which payment will be collected over time as it becomes due under the pricing terms stipulated in the sales agreement. As a practical expedient, when the balance of this U.K. customer is a contract asset, we do not adjust revenue for the effects of a significant financing element as the period between when crude oil is delivered to the customer and when payment is expected to be received is one year or less at contract inception.

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

(In millions)	Year Ended December 31, 2018
Contract asset balance as of January 1, 2018	$ —
Revenue recognized as performance obligations are satisfied	109
Amounts invoiced to customers	(110)
Contract asset (liability) balance as of December 31, 2018	$ (1)

7. Segment Information

We have two reportable operating segments. 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 ("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 and produces and markets products manufactured from natural gas, such as LNG and methanol, in E.G.

Information regarding assets by segment is not presented because it is not reviewed by the chief operating decision maker (“CODM”). Segment income (loss) represents income (loss) 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, proved property impairments, certain exploration expenses relating to a strategic decision to exit conventional exploration, change in tax expense associated with a tax rate change, changes in our valuation allowance, 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**, we closed on the sale of our Canadian business, which includes our Oil Sands Mining segment and exploration stage in-situ leases, in the second quarter of 2017. The Canadian business is reflected as discontinued operations and is excluded from segment information in all historical periods presented.

During the year, we renamed our United States E&P and International E&P segments to the United States and International segments. See **Note 1** for further information.

(In millions)	U.S.	Int'l	Not Allocated to Segments		Total
	Year Ended December 31, 2018				
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 (loss) 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 (loss) / Income (loss) from continuing operations	$ 608	$ 473	$ 15		$ 1,096
Capital expenditures[(a)]	$ 2,620	$ 39	$ 26		$ 2,685

(a) Includes accruals.
(b) Unrealized gain on commodity derivative instruments (see **Note 14**).
(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 impairment 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 18**).

	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	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 (benefit)	1	372	3	376
Segment income (loss) / Income (loss) from continuing operations	$ (148)	$ 374	$ (1,056)	$ (830)
Capital expenditures[(a)]	$ 2,081	$ 42	$ 27	$ 2,150

(a) Includes accruals.
(b) Unrealized loss on commodity derivative instruments (see **Note 14**).
(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 14**).
(g) Includes pension settlement loss of $32 million (see **Note 18**).
(h) Primarily related to the make-whole call provisions paid upon redemption of our senior unsecured notes (see **Note 16**).

(In millions)	Year Ended December 31, 2016 U.S.	Int'l	Not Allocated to Segments	Total
Revenues from contracts with customers	$ 2,331	$ 665	$ —	$ 2,996
Net gain (loss) on commodity derivatives	44	—	(110) (b)	(66)
Marketing revenues	135	105	—	240
Income from equity method investments	—	175	—	175
Net gain (loss) on disposal of assets	8	2	379 (c)	389
Other income	20	30	3	53
Less costs and expenses:				
Production	486	234	—	720
Marketing costs	142	103	—	245
Shipping, handling, and other operating	328	43	113 (d)	484
Exploration	127	17	179 (e)	323
Depreciation, depletion and amortization	1,835	276	45	2,156
Impairments	20	—	47 (f)	67
Taxes other than income	149	—	2	151
General and administrative	94	30	247	371
Net interest and other	—	—	332	332
Other net periodic benefit costs	—	(3)	105 (g)	102
Income tax provision (benefit)	(228)	49	1,102 (h)	923
Segment income (loss) / Income (loss) from continuing operations	$ (415)	$ 228	$ (1,900)	$ (2,087)
Capital expenditures[(a)]	$ 936	$ 82	$ 18	$ 1,036

(a) Includes accruals.
(b) Unrealized loss on commodity derivative instruments (see **Note 14**).
(c) Primarily related to net gain on disposal of assets (see **Note 5**).
(d) Includes termination payment on our Gulf of Mexico deepwater drilling rig commitment of $113 million.
(e) Primarily related to impairments associated with the decision to not drill remaining Gulf of Mexico undeveloped leases (see **Note 11**).
(f) Proved property impairments (see **Note 11**).
(g) Includes pension settlement loss of $103 million (see **Note 18**).
(h) Increased valuation allowance on certain of our deferred tax assets of $1,346 million.

Revenues from external customers (including commodity derivatives) are attributed to geographic areas based upon selling location. The following summarizes revenues from external customers by geographic area.

(In millions)	Year Ended December 31, 2018	2017	2016
United States	$ 4,872	$ 3,086	$ 2,400
Equatorial Guinea	383	530	444
Libya[(a)]	196	431	54
U.K.	360	289	263
Other international	77	37	9
Total	$ 5,888	$ 4,373	$ 3,170

(a) The decrease in 2018 is due to the sale of our Libya subsidiary in the first quarter of 2018 (see **Note 5**).

In 2018, sales to Valero Marketing and Supply and Flint Hills Resources and each of their respective affiliates, each accounted for approximately 11% of our total revenues. In 2017, sales to Vitol and each of their respective affiliates accounted for approximately 10% of our total revenues. In 2016, sales to Valero Marketing and Supply, Tesoro Petroleum, and Flint Hills Resources and each of their respective affiliates accounted for approximately 13%, 11% and 10% of our total revenues.

The following summarizes total revenues from external customers (including commodity derivatives) by product line.

	Year Ended December 31,		
(In millions)	2018	2017	2016
Crude oil and condensate	$ 4,823	$ 3,477	$ 2,605
Natural gas liquids	504	338	198
Natural gas	497	510	356
Other	64	48	11
Total	$ 5,888	$ 4,373	$ 3,170

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

	December 31,	
(In millions)	2018	2017
United States	$ 16,094	$ 15,955
Equatorial Guinea	1,333	1,598
Other international[(a)]	122	959
Total long-lived assets	$ 17,549	$ 18,512

[(a)] The decrease in 2018 is due to the sale of our Libya subsidiary in the first quarter of 2018 (see **Note 5**).

8. Income Taxes

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

	Year Ended December 31,		
(In millions)	2018	2017	2016
United States	$ 642	$ (783)	$ (1,449)
Foreign	785	329	285
Total	$ 1,427	$ (454)	$ (1,164)

Income tax provisions (benefits) for continuing operations were:

	Year Ended December 31,								
	2018			2017			2016		
(In millions)	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
Federal	$ 6	$ —	$ 6	$ (32)	$ 41	$ 9	$ 2	$ 836	$ 838
State and local	(1)	(23)	(24)	(14)	2	(12)	2	8	10
Foreign	274	75	349	483	(104)	379	91	(16)	75
Total	$ 279	$ 52	$ 331	$ 437	$ (61)	$ 376	$ 95	$ 828	$ 923

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)	**2018**	**2017**	**2016**
Total pre-tax income (loss) from continuing operations	$ 1,427	$ (454)	$ (1,164)
Total income tax expense (benefit)	$ 331	$ 376	$ 923
Effective income tax rate on continuing operations	23%	83%	79%
Income taxes at the statutory tax rate[(a)(b)]	$ 300	$ (159)	$ (407)
Effects of foreign operations	214	140	47
Adjustments to valuation allowances	(177)	446	1,270
State income taxes	(17)	(19)	9
Tax law change	—	(35)	6
Other federal tax effects	11	3	(2)
Income tax expense (benefit) on continuing operations	$ 331	$ 376	$ 923

(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 and 2016.

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 increased our tax expense in 2018, 2017 and 2016 due to the mix of pre-tax income between high and low tax jurisdictions, including Libya where the tax rate is 93.5%. Excluding Libya, the effective tax rates on continuing operations would be an expense of 14% in 2018, an expense of 5% in 2017, and an expense of 79% in 2016. 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.

Adjustments to valuation allowances – Since December 31, 2016, we have maintained a full valuation allowance on our net federal deferred tax assets. In 2018, we reduced our valuation allowance by $177 million primarily related to current year activity in the U.S.

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.

Deferred tax assets and liabilities resulted from the following:

	Year Ended December 31,			
(In millions)	2018		2017	
Deferred tax assets:				
Employee benefits	$	102	$	111
Operating loss carryforwards		1,304		1,030
Capital loss carryforwards		2		3
Foreign tax credits		611		611
Other credit carryforwards		—		—
Investments in subsidiaries and affiliates		—		174
Other		5		69
Subtotal		2,024		1,998
Valuation allowance		(749)		(926)
Total deferred tax assets		1,275		1,072
Deferred tax liabilities:				
Property, plant and equipment		1,018		1,332
Accrued revenue		60		81
Other		3		3
Total deferred tax liabilities		1,081		1,416
Net deferred tax liabilities	$	—	$	344
Net deferred tax assets	$	194	$	—

Operating loss carryforwards – At December 31, 2018, 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 $472 million which can be carried forward indefinitely. Foreign operating loss carryforwards include $26 million that begin to expire in 2019. State operating loss carryforwards of $151 million expire in 2019 through 2038.

Valuation allowances – At December 31, 2018, we reflect a valuation allowance in our consolidated balance sheet of $749 million against our net deferred tax assets in various jurisdictions in which we operate.

Property, plant and equipment – At December 31, 2018, we reflected a deferred tax liability of $1,018 million. The reduction primarily relates to the sale of our Libya subsidiary in the first quarter of 2018.

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

	December 31,			
(In millions)	2018		2017	
Assets:				
Other noncurrent assets	$	393	$	489
Liabilities:				
Noncurrent deferred tax liabilities		199		833
Net deferred tax liabilities	$	—	$	344
Net deferred tax assets	$	194	$	—

We are continuously undergoing examination of our U.S. federal income tax returns by the IRS. Such audits have been completed through the 2014 tax year, with the exception of 2010-2011. Based on the status of the proposed settlement in the 2010-2011 IRS Federal Tax Audit ("IRS Audit"), as of December 31, 2018 we have established a receivable of $146 million with $73 million classified in other current assets on the consolidated balance sheet based on the AMT refunds we expect to receive in the next 12 months, and a receivable classified in other noncurrent assets of $73 million on the consolidated balance sheet related to future AMT refunds. As of December 31, 2018, we do not consider the IRS Audit to be effectively settled, however we believe the IRS Audit will be settled within the next 12 months. As a result, we have established an uncertain tax position for the same amount resulting in no impact to the consolidated statement of income for the year ended December 31, 2018. See **Note 25** for further detail. Further, we are routinely involved in U.S. state income tax audits and foreign jurisdiction tax audits. We believe all other audits will be resolved within the amounts paid and/or provided for these liabilities.

As of December 31, 2018, our income tax returns remain subject to examination in the following major tax jurisdictions for the tax years indicated:

United States[(a)]	2008-2017
Equatorial Guinea	2007-2017
United Kingdom	2008-2017

(a) Includes federal and state jurisdictions.

The following table summarizes the activity in unrecognized tax benefits:

(In millions)	2018	2017	2016
Beginning balance	$ 126	$ 66	$ 65
Additions for tax positions of prior years	152	83	6
Reductions for tax positions of prior years	(15)	(3)	(5)
Settlements	—	(20)	—
Statute of limitations	—	—	—
Ending balance	$ 263	$ 126	$ 66

If the unrecognized tax benefits as of December 31, 2018 were recognized, $160 million would affect our effective income tax rate. As of December 31, 2018, there are $251 million uncertain tax positions for which it is reasonably possible that the amount could significantly change during the next twelve months. In the first quarter 2019 we withdrew our appeal in the U.K. related to the timing of certain Brae area decommissioning costs. As a result in the first quarter of 2019 we expect our unrecognized tax benefits to reduce by $68 million with no adverse earnings impact on our consolidated results of operations. See Note 25 for further detail.

Interest and penalties are recorded as part of the tax provision and were $2 million, $27 million and $1 million related to unrecognized tax benefits in 2018, 2017 and 2016. As of December 31, 2018 and 2017, $27 million and $25 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)	2018	2017
Crude oil and natural gas	$ 11	$ 9
Supplies and other items	85	117
Inventories	$ 96	$ 126

10. Property, Plant and Equipment

	December 31,	
(In millions)	2018	2017
United States	$ 16,011	$ 15,867
International[(a)]	710	1,710
Corporate	83	88
Net property, plant and equipment	$ 16,804	$ 17,665

(a) Decrease in 2018 is primarily the result of the sale of our Libya subsidiary in 2018, see Note 5 for further detail.

At December 31, 2018, 2017 and 2016 we had total deferred exploratory well costs as follows:

	December 31,		
(In millions)	**2018**	**2017**	**2016**
Amounts capitalized less than one year after completion of drilling	$ 297	$ 263	$ 131
Amounts capitalized greater than one year after completion of drilling	—	32	118
Total deferred exploratory well costs	$ 297	$ 295	$ 249
Number of projects with costs capitalized greater than one year after completion of drilling	—	1	3

(In millions)	**2018**	**2017**	**2016**
Beginning balance	$ 295	$ 249	$ 437
Additions	262	212	299
Charges to expense[(a)]	(35)	(64)	(23)
Transfers to development	(197)	(102)	(388)
Dispositions[(b)]	(28)	—	(76)
Ending balance	$ 297	$ 295	$ 249

(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) Includes the sale of our Libya subsidiary in 2018 and GOM assets in 2016.

We had no exploratory well costs capitalized greater than one year as of December 31, 2018 and $32 million as of December 31, 2017. During the fourth quarter 2018, we concluded our evaluation of drilling opportunities on the Rodo well in Alba Block Sub Area B, offshore E.G. and determined that we would not pursue further activity. As a result, $32 million in exploratory well costs were expensed.

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.

	2018		**2017**		**2016**	
(In millions)	**Fair Value**	**Impairment**	**Fair Value**	**Impairment**	**Fair Value**	**Impairment**
Long-lived assets held for use	$ 113	$ 75	$ 179	$ 229	$ 15	$ 67

- **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.

- **2016** - Impairments of $67 million, to an aggregate fair value of $15 million, consisted primarily of proved properties in Oklahoma and the Gulf of Mexico in our United States segment as a result of lower forecasted commodity prices and revisions to estimated abandonment costs. 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.

The following table summarizes impairment charges of unproved properties included as a component of exploration expense:

	Year Ended December 31,		
(In millions)	**2018**	**2017**	**2016**
Exploration Expenses			
Unproved property impairments	$ 208	$ 246	$ 195
Dry well costs	47	77	25
Geological and geophysical	21	25	5
Other	13	61	98
Total exploration expenses	$ 289	$ 409	$ 323

Unproved property impairments and dry well costs

- **2018** - During the fourth quarter 2018, we concluded our evaluation of drilling opportunities on the Rodo well in Alba Block Sub Area B, offshore E.G. and determined that we would not pursue further activity. As a result, we expensed $32 million in dry well costs and $16 million in unproved property impairments. See **Note 10** for further discussion.

- **2017** - As a result of lower forecasted long-term commodity prices and the anticipated sales of certain non-core international properties we recorded a non-cash charge of $95 million to unproved property impairments related to various properties; and $64 million in dry well costs related to our Diaba License G4-223 in the Republic of Gabon. Also, as a result of our decision not to develop the Tchicuate offshore Block in the Republic of Gabon, we recorded a non-cash charge of $43 million to unproved property impairments.

- **2016** - Unproved property impairments are primarily a result of our decision to not drill any of our remaining Gulf of Mexico undeveloped leases and also included certain other unproved properties in the United States.

See **Note 5** for relevant detail regarding the disposition of assets and **Note 7** for relevant detail regarding segment presentation of unproved property impairments.

12. Asset Retirement Obligations

Asset retirement obligations primarily consist of estimated costs to remove, dismantle and restore land or seabed 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)	2018	2017
Beginning balance	$ 1,483	$ 1,652
Incurred liabilities, including acquisitions	21	25
Settled liabilities, including dispositions	(117)	(50)
Accretion expense (included in depreciation, depletion and amortization)	70	85
Revisions of estimates	(204)	(227)
Held for sale[(a)]	(108)	(2)
Ending balance[(b)]	$ 1,145	$ 1,483

[(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.

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.
- *Ending balance* primarily relates to the U.K. and includes $64 million classified as short-term at December 31, 2018.

2017

- *Settled liabilities* include dispositions, primarily related to the sale of certain conventional assets in Oklahoma as well as retirements in the U.K. and the Gulf of Mexico.
- *Revisions of estimates* were primarily due to changes in U.K. estimated costs as well as timing of abandonment activities in the U.K.
- *Ending balance* primarily relates to the U.K. and includes $55 million classified as short-term at December 31, 2017.

13. Goodwill

As of December 31, 2018, our consolidated balance sheet included goodwill of $97 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 2018, 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, 2018 and 2017 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 2018 and 2017:

(In millions)	International	
2017		
Beginning balance, gross	$	115
Less: accumulated impairments		—
Beginning balance, net		115
Dispositions		—
Impairment		—
Ending balance, net	$	115
2018		
Beginning balance, gross	$	115
Less: accumulated impairments		—
Beginning balance, net		115
Dispositions [a]		(18)
Impairment		—
Ending balance, net	$	97

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

14. Derivatives

For further information regarding the fair value measurement of derivative instruments see Note 15. See Note 1 for discussion of the types of derivatives we may use and the reasons for them. All of our commodity derivatives and historical 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, 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	

	December 31, 2017						
(In millions)	Asset		Liability		Net Asset (Liability)		Balance Sheet Location
Not Designated as Hedges							
Commodity	$	—	$	138	$	(138)	Other current liabilities
Commodity		—		2		(2)	Deferred credits and other liabilities
Total Not Designated as Hedges	$	—	$	140	$	(140)	

Derivatives Not Designated as Hedges

Terminated Interest Rate Swaps

During the third quarter of 2016, we entered into forward starting interest rate swaps to hedge the variations in cash flows related to fluctuations in long term interest rates from debt that were probable to be refinanced by us in 2018, specifically interest rate risk associated with future changes in the benchmark treasury rate. During the second quarter of 2017, we de-designated the forward starting interest rate swaps previously designated as cash flow hedges. In the third quarter of 2017, the forecasted transaction consummated and we issued $1 billion in senior unsecured notes. As a result, in the third quarter of 2017 we terminated our forward starting interest rate swaps for proceeds of $54 million. We recognized a gain of $46 million, related to deferred gains reclassified from accumulated other comprehensive income, in net interest and other during 2017. See **Note 16** 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).

	Year Ended December 31,		
(In millions)	**2018**	**2017**	**2016**
Interest Rate Swaps			
Beginning balance	$ —	$ 60	$ —
Change in fair value recognized in other comprehensive income	—	(13)	64
Reclassification from other comprehensive income	—	(47)	(4)
Ending balance	$ —	$ —	$ 60

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 2020. These commodity derivatives consist of three-way collars, basis swaps, and NYMEX roll 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/Henry Hub price plus the difference between the floor and the sold put price. These commodity derivatives were not designated as hedges. The following table sets forth outstanding derivative contracts as of December 31, 2018 and the weighted average prices for those contracts:

	2019				2020
Crude Oil	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Full Year**
Three-Way Collars					
Volume (Bbls/day)	70,000	70,000	50,000	50,000	—
Weighted average price per Bbl:					
Ceiling	$71.21	$71.21	$75.88	$75.88	—
Floor	$55.86	$55.86	$57.80	$57.80	—
Sold put	$48.71	$48.71	$50.80	$50.80	—
Basis Swaps [(a)(b)]					
Volume (Bbls/day)	10,000	10,000	10,000	10,000	15,000
Weighted average price per Bbl	$(0.82)	$(0.82)	$(0.82)	$(0.82)	$(0.94)
NYMEX Roll Basis Swaps					
Volume (Bbls/day)	60,000	60,000	60,000	60,000	—
Weighted average price per Bbl	$0.38	$0.38	$0.38	$0.38	—
Natural Gas					
Three-Way Collars					
Volume (MMBtu/day)	200,000	—	—	—	—
Weighted average price per MMBtu:					
Ceiling	$5.25	—	—	—	—
Floor	$3.43	—	—	—	—
Sold put	$2.88	—	—	—	—

(a) The basis differential price is between WTI Midland and WTI Cushing.
(b) Between January 1, 2019 and February 12, 2019, we entered into 5,000 Bbls/day of Midland basis swaps for July - December 2019 with an average price of $(2.55) and 1,000 Bbls/day of Clearbrook basis swaps for March - December 2019 with an average price of $(3.50).

The mark-to-market impact and settlement of these commodity derivative instruments appears in net gain (loss) on commodity derivatives in our consolidated statements of income for the years ended December 31, 2018, 2017, and 2016. The December 31, 2018, 2017, and 2016 mark-to-market impact was a net gain of $267 million, a net loss of $81 million and a net loss of $110 million, respectively. Net settlements of commodity derivative instruments for the years ended December 31, 2018, 2017, and 2016 were a loss of $281 million, a gain of $45 million and a gain of $44 million, respectively.

15. Fair Value Measurements

Fair Values – Recurring

The following tables' present assets and liabilities accounted for at fair value on a recurring basis by hierarchy level.

	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	$ —	$ —	$ —	$ —

	December 31, 2017			
(In millions)	Level 1	Level 2	Level 3	Total
Derivative instruments, assets				
Derivative instruments, assets	$ —	$ —	$ —	$ —
Derivative instruments, liabilities				
Commodity[a]	$ (20)	$ (120)	$ —	$ (140)
Derivative instruments, liabilities	$ (20)	$ (120)	$ —	$ (140)

[a] Derivative instruments are recorded on a net basis in our consolidated balance sheet (see **Note 14**).

Commodity derivatives include three-way collars, basis swaps, and NYMEX roll basis swaps. These instruments are measured at fair value using either a Black-Scholes or a modified Black-Scholes Model. For basis swaps and NYMEX roll 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.

Historically, both our interest rate swaps and forward starting interest rate swaps were measured at fair value with a market approach using actionable broker quotes, which are Level 2 inputs. See **Note 14** for additional discussion of the types of derivative instruments we used.

Fair Values – Goodwill

See **Note 13** 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, 2018 and 2017.

	December 31,			
	2018		2017	
(In millions)	**Fair Value**	**Carrying Amount**	**Fair Value**	**Carrying Amount**
Financial assets				
Current assets[(a)]	$ 13	$ 13	$ 762	$ 761
Other noncurrent assets	76	81	135	137
Total financial assets	$ 89	$ 94	$ 897	$ 898
Financial liabilities				
Other current liabilities	$ 37	$ 58	$ 32	$ 43
Long-term debt, including current portion[(b)]	5,469	5,528	5,976	5,526
Deferred credits and other liabilities	93	88	110	103
Total financial liabilities	$ 5,599	$ 5,674	$ 6,118	$ 5,672

(a) December 31, 2017 fair value and carrying amounts included our two notes receivable relating to the sale of our Canadian business; both were paid during the first quarter of 2018, see Note 5 for further information.
(b) Excludes capital leases and 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.

16. Debt

Revolving Credit Facility

As of December 31, 2018, we had no borrowings against our $3.4 billion unsecured revolving credit facility (as amended, the "Credit Facility"), as described below.

In October 2018, we extended the maturity date of our Credit Facility from May 28, 2021 to May 28, 2022. Fees on the unused commitment to the lenders, as well as the borrowing options under the Credit Facility, remain unaffected by the term extension. We retain the ability to request two one-year extensions and an option to increase the commitment amount by up to an additional $107 million, subject to the consent of any increasing lenders. The sub-facilities for swing-line loans and letters of credit remain unchanged allowing up to an aggregate amount of $100 million and $500 million, respectively.

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, 2018, 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)	**2018**	**2017**
Senior unsecured notes:		
2.700% notes due 2020[(a)]	$ 600	$ 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
Total[(b)]	5,536	5,536
Unamortized discount	(8)	(10)
Unamortized debt issuance cost	(29)	(32)
Total long-term debt	$ 5,499	$ 5,494

(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, 2018 may be declared immediately due and payable.

The following table shows future debt payments:

(In millions)	
2019	$ —
2020	600
2021	—
2022	1,035
2023	201
Thereafter	3,700
Total long-term debt, including current portion	$ 5,536

Debt Issuance

On July 24, 2017, we issued $1 billion in senior unsecured notes that will mature on July 15, 2027. Interest on the senior unsecured notes is payable semi-annually beginning January 15, 2018. We may redeem some or all of the senior unsecured notes at any time at the applicable redemption price, plus accrued interest, if any. We used the net proceeds of $990 million plus existing cash on hand to redeem the following senior unsecured notes:

- $682 million 6.0% Notes Due in 2017
- $854 million 5.9% Notes Due in 2018
- $228 million 7.5% Notes Due in 2019

As a result of the above redemption of $1.76 billion in senior unsecured notes, we recognized a loss on early extinguishment of debt of $46 million, primarily due to make-whole call provisions. In connection with the redemption of the senior unsecured notes, we terminated our forward starting interest rate swaps, which resulted in proceeds of $54 million and a gain of approximately $46 million into earnings in 2017. See **Note 14** for further detail on our historical forward starting interest rate swaps.

Debt Redemption

In December 2017, we entered into a transaction to purchase $1 billion of 3.75% municipal revenue bonds due in 2037, to be issued by the Parish of St. John the Baptist, State of Louisiana (the "Parish"). The Parish will use the proceeds to redeem $1 billion of 5.125% municipal revenue bonds due in 2037 with cash on hand in a refunding transaction. We purchased the $1 billion of 3.75% municipal revenue bonds due in 2037 on their date of issuance to hold for our own account and potential remarketing to the public at a future date.

17. Incentive Based Compensation

Description of stock-based compensation plans – The Marathon Oil Corporation 2016 Incentive Compensation Plan (the "2016 Plan") was approved by our stockholders in May 2016 and authorizes the Compensation Committee of the Board of Directors to grant stock options, SARs, stock awards (including restricted stock and restricted stock unit awards) and performance unit awards to employees. The 2016 Plan also allows us to provide equity compensation to our non-employee directors. No more than 55 million shares of our common stock may be issued under the 2016 Plan. For stock options and SARs, the number of shares available for issuance under the 2016 Plan will be reduced by one share for each share of our common stock in respect of which the award is granted. For stock awards (including restricted stock and restricted stock unit awards), the number of shares available for issuance under the 2016 Plan will be reduced by 2.41 shares for each share of our common stock in respect of which the award is granted.

Shares subject to awards under the 2016 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 2016 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 2016 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 2016 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 2016 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, 2018, there are no SARs outstanding.

Restricted stock – We grant restricted stock under the 2016 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 2016 Plan. At the grant date, each unit represents the value of one share of our common stock. These units are settled in cash, and the amount of the payment is based on (1) the vesting percentage, which can be from zero to 200% based on performance achieved and as determined by the Compensation Committee of the Board of Directors and (2) the fair market value of our common stock on the last day of the performance period. 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 number of shares that would 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. We also grant restricted stock units to certain non-officer international employees which generally vest ratably over a three-year period, contingent on the recipient's continued employment. Grants of restricted stock units to these non-officer international employees are 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 $53 million, $50 million and $51 million in 2018, 2017 and 2016, while the total related income tax benefits were $19 million in 2016. Due to the full valuation allowance on our net federal deferred tax assets, we realized no tax benefit during 2018 and 2017. In 2018 and 2016, cash received upon exercise of stock option awards was $26 million and $1 million. There was no cash received upon exercise of stock option awards for 2017. There were no tax benefits realized for deductions for stock awards settled during 2018, 2017 and 2016.

Stock option awards – During 2018, 2017 and 2016 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:

	2018	2017	2016
Exercise price per share	$14.52	$15.80	$7.22
Expected annual dividend yield	1.4%	1.3%	2.8%
Expected life in years	6.45	6.4	6.3
Expected volatility	43%	42%	36%
Risk-free interest rate	2.8%	2.1%	1.4%
Weighted average grant date fair value of stock option awards granted	$5.83	$6.07	$1.97

The following is a summary of stock option award activity in 2018.

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value *(in millions)*
Outstanding at beginning of year	10,330,776	$25.52		
Granted	856,890	$14.52		
Exercised	(1,878,836)	$14.02		
Canceled	(3,128,823)	$31.64		
Outstanding at end of year	6,180,007	$24.39	5 years	$ 4
Exercisable at end of year	4,523,008	$28.46	3 years	$ 1
Expected to vest	1,635,216	$13.25	8 years	$ 3

The intrinsic value of stock option awards exercised during 2018 was $13 million while it was immaterial during 2017 and 2016.

As of December 31, 2018, unrecognized compensation cost related to stock option awards was $5 million, which is expected to be recognized over a weighted average period of one year.

Restricted stock awards and restricted stock units – The following is a summary of restricted stock and restricted stock unit award activity in 2018.

	Awards	Weighted Average Grant Date Fair Value
Unvested at beginning of year	7,572,845	$14.24
Granted	4,817,577	$14.82
Vested and Exercised	(3,003,321)	$15.79
Canceled	(882,155)	$14.06
Unvested at end of year	8,504,946	$14.04

The vesting date fair value of restricted stock awards which vested during 2018, 2017 and 2016 was $48 million, $39 million and $20 million. The weighted average grant date fair value of restricted stock awards was $14.04, $14.24 and $14.44 for awards unvested at December 31, 2018, 2017 and 2016.

As of December 31, 2018 there was $74 million of unrecognized compensation cost related to restricted stock awards which is expected to be recognized over a weighted average period of one year.

Stock-based performance unit awards – During 2018, 2017 and 2016 we granted 754,140, 563,631 and 1,205,517 stock-based performance unit awards to officers. At December 31, 2018, there were 1,196,176 units outstanding. Total stock-based performance unit awards expense was $13 million in 2018, $8 million in 2017 and $6 million in 2016.

The key assumptions used in the Monte Carlo simulation to determine the fair value of stock-based performance units granted in 2018, 2017 and 2016 were:

	2018	2017	2016
Valuation date stock price	$14.17	$14.17	$14.17
Expected annual dividend yield	1.4%	1.4%	1.4%
Expected volatility	39%	43%	52%
Risk-free interest rate	2.5%	2.6%	2.4%
Fair value of stock-based performance units outstanding	$19.60	$19.45	$21.51

18. Defined Benefit Postretirement Plans and Defined Contribution Plan

We have noncontributory defined benefit pension plans covering substantially all domestic employees, as well as U.K. employees who were hired before April 2010. Certain employees located in E.G., who are U.S. or U.K. based, also participate in these plans. Benefits under these plans are based on plan provisions specific to each plan. For the U.K. pension plan, the principal employer and plan trustees reached a decision to close the plan to future benefit accruals effective December 31, 2015.

We also have defined benefit 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	
	2018		2017		2018	2017
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	U.S.
Accumulated benefit obligation	$ 320	$ 511	$ 378	$ 599	$ 96	$ 221
Change in benefit obligations:						
Beginning balance	$ 384	$ 599	$ 397	$ 583	$ 221	$ 227
Service cost	18	—	22	—	2	2
Interest cost	12	14	13	17	7	8
Plan amendment	—	3	—	—	(99)	—
Actuarial loss (gain)	(20)	(38)	42	(7)	(15)	5
Foreign currency exchange rate changes	—	(29)	—	52	—	—
Settlements paid	(62)	(23)	(84)	(31)	—	—
Benefits paid	(6)	(15)	(6)	(15)	(20)	(21)
Ending balance	$ 326	$ 511	$ 384	$ 599	$ 96	$ 221
Change in fair value of plan assets:						
Beginning balance	$ 216	$ 670	$ 227	$ 595	$ —	$ —
Actual return on plan assets	(6)	(21)	27	47	—	—
Employer contributions	61	17	52	17	20	21
Foreign currency exchange rate changes	—	(34)	—	57	—	—
Settlements paid	(62)	(23)	(84)	(31)	—	—
Benefits paid	(6)	(15)	(6)	(15)	(20)	(21)
Ending balance	$ 203	$ 594	$ 216	$ 670	$ —	$ —
Funded status of plans at December 31	$ (123)	$ 83	$ (168)	$ 71	$ (96)	$ (221)
Amounts recognized in the consolidated balance sheets:						
Noncurrent assets	$ —	$ 83	$ —	$ 71	$ —	$ —
Current liabilities	(5)	—	(6)	—	(19)	(21)
Noncurrent liabilities	(118)	—	(162)	—	(77)	(200)
Accrued benefit cost	$ (123)	$ 83	$ (168)	$ 71	$ (96)	$ (221)
Pretax amounts in accumulated other comprehensive loss:						
Net loss (gain)	$ 90	$ 59	$ 122	$ 58	$ 14	$ 30
Prior service cost (credit)	(36)	5	(45)	3	(147)	(56)

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,		
	2018		2017		2016		2018	2017	2016
(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	$ 18	$ —	$ 22	$ —	$ 25	$ —	$ 2	$ 2	$ 2
Interest cost	12	14	13	17	16	23	7	8	11
Expected return on plan assets	(11)	(24)	(13)	(30)	(18)	(35)	—	—	—
Amortization:									
- prior service cost (credit)	(10)	—	(10)	—	(10)	1	(8)	(7)	(3)
- actuarial loss	11	—	8	1	14	—	1	—	—
Net settlement loss[a]	18	3	28	4	97	6	—	—	—
Net periodic benefit cost[b]	$ 38	$ (7)	$ 48	$ (8)	$ 124	$ (5)	$ 2	$ 3	$ 10
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss (pretax):									
Actuarial loss (gain)	$ (4)	$ 8	$ 28	$ (26)	$ 70	$ 41	$ (15)	$ 5	$ 11
Amortization of actuarial gain (loss)	(29)	(3)	(36)	(4)	(111)	(6)	(1)	—	—
Prior service cost (credit)	—	3	—	—	—	1	(99)	—	(38)
Amortization of prior service credit (cost)	10	—	10	—	10	(1)	8	7	3
Total recognized in other comprehensive (income) loss	$ (23)	$ 8	$ 2	$ (30)	$ (31)	$ 35	$ (107)	$ 12	$ (24)
Total recognized in net periodic benefit cost and other comprehensive (income) loss	$ 15	$ 1	$ 50	$ (38)	$ 93	$ 30	$ (105)	$ 15	$ (14)

(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 2019 are $7 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 2019 are $1 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 2018, 2017 and 2016.

	Pension Benefits						Other Benefits		
	2018		2017		2016		2018	2017	2016
(In millions)	U.S.	Int'l	U.S.	Int'l	U.S.	Int'l	U.S.	U.S.	U.S.
Weighted average assumptions used to determine benefit obligation:									
Discount rate	4.26%	2.90%	3.55%	2.50%	4.02%	2.70%	4.09%	3.54%	3.98%
Rate of compensation increase[a]	4.00%	—%	4.00%	—%	4.00%	—%	4.00%	4.00%	4.00%
Weighted average assumptions used to determine net periodic benefit cost:									
Discount rate	3.88%	2.50%	3.86%	2.70%	3.66%	3.90%	3.54%	3.98%	4.36%
Expected long-term return on plan assets	6.50%	3.70%	6.50%	4.50%	6.75%	5.50%	—%	—%	—%
Rate of compensation increase[a]	4.00%	—%	4.00%	—%	4.00%	—%	4.00%	4.00%	4.00%

(a) No future benefits will be incurred for the U.K. plan after December 31, 2015. Therefore, rate of compensation increase is no longer applicable to this plan.

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

	2018	2017	2016
Initial health care trend rate	N/A	8.00%	8.25%
Ultimate trend rate	N/A	4.70%	4.50%
Year ultimate trend rate is reached	N/A	2025	2025

N/A All retiree medical subsidies are frozen as of January 1, 2019.

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.

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 – Our international plan's target asset allocation is comprised of 55% equity securities and 45% fixed income securities. The plan assets are invested in ten separate portfolios, mainly pooled fund vehicles, managed by several professional investment managers whose performance is measured independently by a third-party asset servicing consulting firm.

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, 2018 and 2017.

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. Other fixed income investments include futures contracts, real estate investment trusts, credit default, zero coupon, 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, 2018 and 2017.

	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

	December 31, 2017							
(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	$ 6	$ 1	$ —	$ —	$ —	$ —	$ 6	$ 1
Equity securities:								
Common stock	81	—	—	—	—	—	81	—
Private equity	—	—	—	—	16	—	16	—
Pooled funds	—	—	—	266	—	—	—	266
Fixed income securities:								
Corporate	—	—	6	—	—	—	6	—
Exchange traded funds	5	—	—	—	—	—	5	—
Government	19	—	2	—	3	—	24	—
Pooled funds	—	—	—	403	—	—	—	403
Other	—	—	—	—	19	—	19	—
Total investments, at fair value	111	1	8	669	38	—	157	670
Commingled funds[b]	—	—	—	—	—	—	59	—
Total investments	$ 111	$ 1	$ 8	$ 669	$ 38	$ —	$ 216	$ 670

[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. See Note 2 for further information on the FASB update.

The activity during the year ended December 31, 2018 and 2017, 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, 2018 and reflect expected future services, as appropriate, are to be paid in the years indicated.

	Pension Benefits		Other Benefits
(In millions)	U.S.	Int'l	U.S.
2019	$ 38	$ 18	$ 18
2020	34	18	18
2021	31	20	9
2022	29	21	8
2023	27	23	7
2024 through 2028	114	127	27

Contributions to defined benefit plans – We expect to make contributions to the funded pension plans of up to $50 million in 2019. Cash contributions to be paid from our general assets for the unfunded pension and postretirement plans are expected to be approximately $5 million and $18 million in 2019.

Contributions to defined contribution plans – We contribute to several defined contribution plans for eligible employees. Contributions to these plans totaled $22 million, $20 million and $20 million in 2018, 2017 and 2016.

19. 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)	2018	2017	Income Statement Line
Postretirement and postemployment plans			
Amortization of prior service credit	$ 18	$ 17	Other net periodic benefit costs
Amortization of actuarial loss	(12)	(9)	Other net periodic benefit costs
Net settlement loss	(21)	(32)	Other net periodic benefit costs
Derivative hedges			
Recognized gain on terminated derivative hedge	—	46	Net interest and other
Ineffective portion of derivative hedge	—	1	Net interest and other
	(15)	23	Income (loss) from continuing operations before income taxes
	1	(40)	(Provision) benefit for income taxes
Total reclassifications to expense, net of tax	$ (14)	$ (17)	Income (loss) from continuing operations
Foreign currency hedges			
Net recognized loss in discontinued operations, net of tax	—	(30)	Income (loss) from discontinued operations
Total reclassifications to expense	$ (14)	$ (47)	Net income (loss)

20. Supplemental Cash Flow Information

(In millions)	Year Ended December 31, 2018	2017	2016
Net cash used in operating activities:			
Interest paid, net of amounts capitalized	$ (270)	$ (379)	$ (375)
Income taxes paid to taxing authorities[a]	(323)	(391)	(84)
Noncash investing activities, related to continuing operations:			
Increase (decrease) asset retirement costs	$ (183)	$ (202)	$ 110
Asset retirement obligations assumed by buyer	(82)	14	40
Notes receivable for disposition of assets	—	748	—

[a] 2017 includes a payment of $108 million made to the U.K. tax authorities to preserve our appeal rights, see **Note 25** for additional discussion.

Other noncash investing activities include accrued capital expenditures as of December 31, 2018, 2017 and 2016 of $250 million, $329 million and $155 million.

21. Other Items

Net interest and other

(In millions)	Year Ended December 31, 2018	2017	2016
Interest:			
Interest income	$ 32	$ 34	$ 14
Interest expense	(280)	(380)	(398)
Income on interest rate swaps	—	53	13
Interest capitalized	—	3	18
Total interest	(248)	(290)	(353)
Other:			
Net foreign currency gain (loss)	9	8	6
Other	13	12	15
Total other	22	20	21
Net interest and other	$ (226)	$ (270)	$ (332)

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

(In millions)	Year Ended December 31, 2018	2017	2016
Net interest and other	$ 9	$ 8	$ 6
Provision for income taxes	10	57	(32)
Aggregate foreign currency gains (losses)	$ 19	$ 65	$ (26)

22. Equity Method Investments

During 2018, 2017 and 2016 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% 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, 2018	December 31, 2018	December 31, 2017
EGHoldings	60%	$ 402	$ 456
Alba Plant LLC	52%	167	214
AMPCO	45%	176	177
Total		$ 745	$ 847

Dividends and partnership distributions received from equity method investees (excluding distributions that represented a return of capital previously contributed) were $270 million in 2018, $276 million in 2017 and $192 million in 2016.

Summarized financial information for equity method investees is as follows:

(In millions)	2018	2017	2016
Income data – year:[(a)]			
Revenues and other income	$ 1,269	$ 1,294	$ 770
Income from operations	588	631	346
Net income	459	508	313
Balance sheet data – December 31:			
Current assets	$ 559	$ 586	
Noncurrent assets	931	1,044	
Current liabilities	253	221	
Noncurrent liabilities	87	94	

[(a)] See Item 15 Exhibits, Financial Statement Schedules which contains the Alba Plant LLC unaudited financial statements, which have been included pursuant to Rule 3-09 of Regulation S-X.

Revenues from related parties were $48 million, $60 million and $54 million in 2018, 2017 and 2016, with the majority related to EGHoldings in all years. We had no purchases from related parties in 2018 and $132 million and $103 million in 2017 and 2016 with the majority related to Alba Plant LLC in all years.

Current receivables from related parties at December 31, 2018 and 2017, were $25 million and $24 million with the majority related to EGHoldings. Payables to related parties were $15 million and $14 million at December 31, 2018 and 2017, with the majority related to Alba Plant LLC.

23. Stockholders' Equity

During 2018 we acquired 36 million of common shares at a cost of $700 million under our share repurchase program. As of December 31, 2018 the total remaining share repurchase authorization was $800 million. 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 prior to completion. The repurchase program does not include specific price targets or timetables. Shares repurchased as of December 31, 2018 were held as treasury stock. There were no share repurchases during 2017 under our publicly announced plans or programs.

24. Leases

We lease a wide variety of facilities and equipment under operating leases, including land, building space, equipment and vehicles. Most long-term leases include renewal options and, in certain leases, purchase options. Future minimum commitments for operating lease obligations having noncancellable lease terms in excess of one year are as follows:

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

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

Operating lease rental expense related to continuing operations was $99 million, $87 million and $87 million in 2018, 2017 and 2016.

25. Commitments and Contingencies

The U.K. tax authorities have challenged the timing of deductibility for certain Brae area decommissioning costs, which we claimed for U.K. corporation tax purposes. The dispute relates to the timing of the deduction and does not dispute the general deductibility of decommissioning costs. In the fourth quarter of 2017, we received notification from the U.K.'s First-tier Tribunal that the decommissioning cost deductions, which we had claimed, were not allowable. In accordance with U.K. regulations, in the fourth quarter of 2017, we paid the amount of tax and interest in question, approximately $108 million, prior to our appeal. In the first quarter of 2019 we withdrew our appeal on this matter, the resulting revisions to current and deferred tax liabilities are expected to have no cumulative adverse earnings impact on our consolidated results of operations. See **Note 8** for further detail.

We are continuously undergoing examination of our U.S. federal income tax returns by the IRS. These audits have been completed through the 2014 tax year, except for tax years 2010 and 2011. During the third quarter of 2017, we received a partnership adjustment notification related to the 2010 and 2011 tax years, for which we have filed a Tax Court Petition in the fourth quarter of 2017. We believe that it is more likely than not that we will prevail. See **Note 8** for further detail.

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, 2018 and 2017, 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, 2018 and 2017, contractual commitments to acquire property, plant and equipment totaled $57 million and $102 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, up to $70 million, 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)	2018				2017			
	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
Revenues from contracts with customers	$ 1,537	$ 1,447	$ 1,538	$ 1,380	$ 873	$ 902	$ 1,136	$ 1,336
Income (loss) from continuing operations before income taxes[(a)(b)]	524	140	357	406	(16)	(112)	(458)	132
Income (loss) from continuing operations	356	96	254	390	(50)	(153)	(599)	(28)
Discontinued operations[(c)]	—	—	—	—	(4,907)	14	—	—
Net income (loss)	$ 356	$ 96	$ 254	$ 390	$ (4,957)	$ (139)	$ (599)	$ (28)
Income (loss) per basic share:								
Continuing operations	$ 0.42	$ 0.11	$ 0.30	$ 0.47	$ (0.06)	$ (0.18)	$ (0.70)	$ (0.03)
Discontinued operations[(c)]	$ —	$ —	$ —	$ —	$ (5.78)	$ 0.02	$ —	$ —
Net income (loss)	$ 0.42	$ 0.11	$ 0.30	$ 0.47	$ (5.84)	$ (0.16)	$ (0.70)	$ (0.03)
Dividends paid per share	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05

(a) For 2018, includes unproved property impairments and exploratory dry well costs of $49 million in the fourth quarter of 2018. For 2017, includes impairments to proved properties of $201 million and $24 million in the third quarter and fourth quarter, respectively. Also includes unproved property impairments and exploratory dry well costs of $215 million in the third quarter of 2017. (See Item 8. Financial Statements and Supplementary Data – **Note 11** to the consolidated financial statements).

(b) The fourth quarter of 2018 includes a mark-to-market gain on commodity derivatives of $336 million. 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).

(c) We closed on the sale of our Canadian business in the second quarter of 2017. The Canadian business is reflected as discontinued operations in all periods presented. Included in the first quarter of 2017 is an after-tax non-cash impairment charge of $4.96 billion, primarily related to the property, plant, and equipment.

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. We closed on the sale of our subsidiary, Marathon Oil Libya Limited, in 2018 and have not reflected this business as discontinued operations ("Disc Ops") in the periods presented. We closed the sale of our Canada business in 2017 and have reflected this business as Disc Ops in 2017 and 2016. See **Note 5** for further details on dispositions.

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, NGL, 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 three years of industry experience with at least one year in reserve estimation and have completed our QRE training course. All reserves changes (including proved) must be approved by the 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 32 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 engage third-party consultants to provide, at a minimum, independent estimates for fields that comprise 80% of our total proved reserves over a rolling four-year period. We exceeded this percentage for the four-year period ended December 31, 2018, with 94% of our total proved reserves independently audited. An audit tolerance at a field level of +/- 10% to our internal estimates has been established. Should the third-party consultants' initial analysis fall outside our tolerance band, both parties will re-examine the information provided, request additional data and refine their analysis, if appropriate. In the very limited instances where differences outside the 10% tolerance cannot be resolved by year end, a plan to resolve the difference is developed and executive management consent is obtained. The audit process did not result in any significant changes to our reserve estimates for 2018, 2017 or 2016.

For the year ended December 31, 2016, Netherland, Sewell & Associates, Inc. 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 Society of Petroleum Engineers. The senior technical advisor has over 14 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 12 years of practical experience in petroleum geosciences and is a licensed Professional Geoscientist in the State of Texas.

Ryder Scott Company also performed audits of the prior years' reserves for several of our fields in 2018, 2017 and 2016. Their summary reports are filed as exhibits to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 36 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.

Estimated Quantities of Proved Oil and Gas Reserves

The estimation of net recoverable quantities of crude oil and condensate, natural gas liquids, 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. See **Item 1A. Risk Factors** and **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Estimates** for the table providing our 2018 SEC pricing of benchmark prices and the underlying assumptions used.

The table below provides the 2018 SEC pricing for certain benchmark prices:

		2018 SEC Pricing
WTI Crude oil (per bbl)	$	65.56
Henry Hub natural gas (per mmbtu)	$	3.05
Brent crude oil (per bbl)	$	72.70
Mont Belvieu NGLs (per bbl)	$	26.63

Estimated Quantities of Proved Oil and Gas Reserves

(mmbbl)	U.S.	E.G.[a]	Libya	Other Int'l	Cont Ops	Disc Ops	Total
Crude oil and condensate							
Proved developed and undeveloped reserves:							
Beginning of year - 2016	580	52	201	22	855	—	855
Revisions of previous estimates	55	1	(28)	3	31	—	31
Improved recovery	4	—	—	—	4	—	4
Purchases of reserves in place	12	—	—	—	12	—	12
Extensions, discoveries and other additions	37	—	—	1	38	—	38
Production	(48)	(8)	(1)	(4)	(61)	—	(61)
Sales of reserves in place	(77)	—	—	—	(77)	—	(77)
End of year - 2016	563	45	172	22	802	—	802
Revisions of previous estimates	9	(2)	—	8	15	—	15
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	18	—	—	—	18	—	18
Extensions, discoveries and other additions	30	4	—	—	34	—	34
Production	(49)	(8)	(7)	(4)	(68)	—	(68)
Sales of reserves in place	(1)	—	—	—	(1)	—	(1)
End of year - 2017	570	39	165	26	800	—	800
Revisions of previous estimates	49	3	—	3	55	—	55
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	—	—	—	—	—	—	—
Extensions, discoveries and other additions	42	—	—	2	44	—	44
Production	(63)	(6)	(3)	(5)	(77)	—	(77)
Sales of reserves in place	(3)	—	(162)	(1)	(166)	—	(166)
End of year - 2018	595	36	—	25	656	—	656
Proved developed reserves:							
Beginning of year - 2016	327	25	173	16	541	—	541
End of year - 2016	238	45	172	13	468	—	468
End of year - 2017	263	39	165	17	484	—	484
End of year - 2018	287	36	—	22	345	—	345
Proved undeveloped reserves:							
Beginning of year - 2016	253	27	28	6	314	—	314
End of year - 2016	325	—	—	9	334	—	334
End of year - 2017	307	—	—	9	316	—	316
End of year - 2018	308	—	—	3	311	—	311

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	E.G.[a]	Libya	Other Int'l	Cont Ops	Disc Ops	Total
Natural gas liquids							
Proved developed and undeveloped reserves:							
Beginning of year - 2016	172	28	—	—	200	—	200
Revisions of previous estimates	(8)	—	—	—	(8)	—	(8)
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	12	—	—	—	12	—	12
Extensions, discoveries and other additions	11	—	—	—	11	—	11
Production	(14)	(4)	—	—	(18)	—	(18)
Sales of reserves in place	(3)	—	—	—	(3)	—	(3)
End of year - 2016	170	24	—	—	194	—	194
Revisions of previous estimates	37	3	—	—	40	—	40
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	5	—	—	—	5	—	5
Extensions, discoveries and other additions	34	2	—	—	36	—	36
Production	(16)	(4)	—	—	(20)	—	(20)
Sales of reserves in place	(1)	—	—	—	(1)	—	(1)
End of year - 2017	229	25	—	—	254	—	254
Revisions of previous estimates	(9)	1	—	—	(8)	—	(8)
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	—	—	—	—	—	—	—
Extensions, discoveries and other additions	25	—	—	—	25	—	25
Production	(20)	(4)	—	—	(24)	—	(24)
Sales of reserves in place	(1)	—	—	—	(1)	—	(1)
End of year - 2018	224	22	—	—	246	—	246
Proved developed reserves:							
Beginning of year - 2016	92	12	—	—	104	—	104
End of year - 2016	78	24	—	—	102	—	102
End of year - 2017	118	25	—	—	143	—	143
End of year - 2018	119	22	—	—	141	—	141
Proved undeveloped reserves:							
Beginning of year - 2016	80	16	—	—	96	—	96
End of year - 2016	92	—	—	—	92	—	92
End of year - 2017	111	—	—	—	111	—	111
End of year - 2018	105	—	—	—	105	—	105

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(bcf)	U.S.	E.G.[(a)]	Libya	Other Int'l	Cont Ops	Disc Ops	Total
Natural gas							
Proved developed and undeveloped reserves:							
Beginning of year - 2016	1,151	1,090	206	15	2,462	—	2,462
Revisions of previous estimates	145	8	(1)	3	155	—	155
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	61	—	—	—	61	—	61
Extensions, discoveries and other additions	71	—	—	—	71	—	71
Production [(b)]	(115)	(155)	—	(8)	(278)	—	(278)
Sales of reserves in place	(25)	—	—	—	(25)	—	(25)
End of year - 2016	1,288	943	205	10	2,446	—	2,446
Revisions of previous estimates	(33)	(18)	—	4	(47)	—	(47)
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	36	—	—	—	36	—	36
Extensions, discoveries and other additions	204	76	—	—	280	—	280
Production [(b)]	(127)	(168)	(1)	(6)	(302)	—	(302)
Sales of reserves in place	(44)	—	—	—	(44)	—	(44)
End of year - 2017	1,324	833	204	8	2,369	—	2,369
Revisions of previous estimates	188	35	—	4	227	—	227
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	—	—	—	—	—	—	—
Extensions, discoveries and other additions	198	—	—	—	198	—	198
Production [(b)]	(156)	(153)	(1)	(5)	(315)	—	(315)
Sales of reserves in place	(1)	—	(203)	—	(204)	—	(204)
End of year - 2018	1,553	715	—	7	2,275	—	2,275
Proved developed reserves:							
Beginning of year - 2016	640	552	94	11	1,297	—	1,297
End of year - 2016	648	943	95	5	1,691	—	1,691
End of year - 2017	726	833	94	2	1,655	—	1,655
End of year - 2018	869	715	—	7	1,591	—	1,591
Proved undeveloped reserves:							
Beginning of year - 2016	511	538	112	4	1,165	—	1,165
End of year - 2016	640	—	110	5	755	—	755
End of year - 2017	598	—	110	6	714	—	714
End of year - 2018	684	—	—	—	684	—	684

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmbbl)	U.S.	E.G.[a]	Libya	Other Int'l	Cont Ops	Disc Ops	Total
Synthetic crude oil							
Proved developed and undeveloped reserves:							
Beginning of year - 2016	—	—	—	—	—	698	698
Revisions of previous estimates	—	—	—	—	—	12	12
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	—	—	—	—	—	—	—
Extensions, discoveries and other additions	—	—	—	—	—	—	—
Production	—	—	—	—	—	(18)	(18)
Sales of reserves in place	—	—	—	—	—	—	—
End of year - 2016	—	—	—	—	—	692	692
Revisions of previous estimates	—	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	—	—	—	—	—	—	—
Extensions, discoveries and other additions	—	—	—	—	—	—	—
Production	—	—	—	—	—	(7)	(7)
Sales of reserves in place	—	—	—	—	—	(685)	(685)
End of year - 2017	—	—	—	—	—	—	—
Revisions of previous estimates	—	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	—	—	—	—	—	—	—
Extensions, discoveries and other additions	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
Sales of reserves in place	—	—	—	—	—	—	—
End of year - 2018	—	—	—	—	—	—	—
Proved developed reserves:							
Beginning of year - 2016	—	—	—	—	—	698	698
End of year - 2016	—	—	—	—	—	692	692
End of year - 2017	—	—	—	—	—	—	—
End of year - 2018	—	—	—	—	—	—	—
Proved undeveloped reserves:							
Beginning of year - 2016	—	—	—	—	—	—	—
End of year - 2016	—	—	—	—	—	—	—
End of year - 2017	—	—	—	—	—	—	—
End of year - 2018	—	—	—	—	—	—	—

Estimated Quantities of Proved Oil and Gas Reserves (continued)

(mmboe)	U.S.	E.G.[a]	Libya	Other Int'l	Cont Ops	Disc Ops	Total
Total Proved Reserves							
Proved developed and undeveloped reserves:							
Beginning of year - 2016	944	261	235	25	1,465	698	2,163
Revisions of previous estimates	73	2	(28)	4	51	12	63
Improved recovery	4	—	—	—	4	—	4
Purchases of reserves in place	34	—	—	—	34	—	34
Extensions, discoveries and other additions	59	—	—	1	60	—	60
Production [b]	(82)	(37)	(1)	(6)	(126)	(18)	(144)
Sales of reserves in place	(84)	—	—	—	(84)	—	(84)
End of year - 2016	948	226	206	24	1,404	692	2,096
Revisions of previous estimates	42	(1)	—	8	49	—	49
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	28	—	—	—	28	—	28
Extensions, discoveries and other additions	98	18	—	—	116	—	116
Production [b]	(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
Improved recovery	—	—	—	—	—	—	—
Purchases of reserves in place	—	—		—	—	—	—
Extensions, discoveries and other additions	100	—	—	2	102	—	102
Production [b]	(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
Proved developed reserves:							
Beginning of year - 2016	526	129	189	18	862	698	1,560
End of year - 2016	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
Proved undeveloped reserves:							
Beginning of year - 2016	418	132	46	7	603	—	603
End of year - 2016	524	—	18	10	552	—	552
End of year - 2017	518	—	18	10	546	—	546
End of year - 2018	526	—	—	3	529	—	529

(a) Consists of estimated reserves from properties governed by production sharing contracts.
(b) Excludes the resale of purchased natural gas used in reservoir management.

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

- *Revisions of previous estimates:* Increased by 84 mmboe including an increase of 108 mmboe associated with the acceleration of higher economic wells in the U.S. resource plays into the 5-year plan and an increase of 15 mmboe associated with wells to sales that were additions to the plan, partially offset by a decrease of 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 due to an increase of 69 mmboe associated with the expansion of proved areas and an increase of 33 mmboe associated with wells to sales from unproved categories.
- *Production:* Decreased by 153 mmboe.
- *Sales of reserves in place:* Decreased by 201 mmboe including 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, and 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 primarily due to the acceleration of higher economic wells in the Bakken into the 5-year plan resulting in an increase of 44 mmboe, with 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 including 685 mmboe associated with the sale of our Canadian business and 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.

2016 proved reserves decreased by 67 mmboe primarily due to the following:

- *Revisions of previous estimates:* Increased by 63 mmboe primarily due to an increase of 151 mmboe associated with the acceleration of higher economic wells in the U.S. resource plays into the 5-year plan and a decrease of 64 mmboe due to U.S. technical revisions.
- *Extensions, discoveries, and other additions:* Increased by 60 mmboe primarily associated with the expansion of proved areas and new wells to sales from unproven categories in Oklahoma.
- *Purchases of reserves in place:* Increased by 34 mmboe from acquisition of STACK assets in Oklahoma.
- *Production:* Decreased by 144 mmboe.
- *Sales of reserves in place:* Decreased by 84 mmboe associated with the divestitures of certain Wyoming and Gulf of Mexico assets.

Changes in Proved Undeveloped Reserves

As of December 31, 2018, 529 mmboe of proved undeveloped reserves were reported, a decrease of 17 mmboe from December 31, 2017. The following table shows changes in proved undeveloped reserves for 2018:

(mmboe)	
Beginning of year	546
Revisions of previous estimates	47
Extensions, discoveries, and other additions	61
Dispositions	(19)
Transfers to proved developed	(106)
End of year	529

Revisions of prior estimates. Increased by 47 mmboe due to an increase of 108 mmboe associated with the acceleration of higher economic wells in the U.S. resource plays into the 5-year plan partially offset by a decrease of 61 mmboe due to technical revisions across the business.

Extensions, discoveries and other additions. Increased by 61 mmboe due to the expansion of proved areas in the U.S. resource plays.

Transfers to proved developed. 106 mmboe of PUD reserves were converted to proved developed status during 2018, primarily from assets in our U.S. resource plays. This 2018 transfer equates to a 19% PUD conversion rate and a 5-year average annual PUD conversion rate during the 2014-2018 period of 18%. All proved undeveloped reserve drilling locations are scheduled to be drilled prior to the end of 2023. There are no proved undeveloped reserves on the books beyond 5 years as of December 31, 2018.

Costs Incurred & Future Costs to Develop

Costs incurred in 2018, 2017 and 2016 relating to the development of proved undeveloped reserves were $1,082 million, $842 million and $359 million. As of December 31, 2018, future development costs estimated to be required for the development of proved undeveloped crude oil and condensate, NGLs and natural gas reserves for the years 2019 through 2023 are projected to be $1,541 million, $1,595 million, $1,737 million, $1,398 million and $1,116 million.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization

(In millions)	**U.S.**	**E.G.**	**Libya**	**Other Int'l**	**Total**
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
Year Ended December 31, 2017					
Capitalized Costs:					
Proved properties	$ 27,477	$ 1,990	$ 830	$ 5,050	$ 35,347
Unproved properties	2,755	110	217	76	3,158
Total	30,232	2,100	1,047	5,126	38,505
Accumulated depreciation, depletion and amortization:					
Proved properties	14,254	1,348	289	4,850	20,741
Unproved properties[(a)]	206	—	—	76	282
Total	14,460	1,348	289	4,926	21,023
Net capitalized costs	$ 15,772	$ 752	$ 758	$ 200	$ 17,482

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

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, 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
December 31, 2016							
Property acquisition:							
Proved	$ 276	$ —	$ —	$ —	$ 276	$ —	$ 276
Unproved	642	—	—	(10)	632	—	632
Exploration	525	1	—	13	539	—	539
Development	456	55	3	121 [(b)]	635	31	666
Total	$ 1,899	$ 56	$ 3	$ 124	$ 2,082	$ 31	$ 2,113

[(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 in the U.K.

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, 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	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	(1)	(50)	(333)	13	(371)	1,674	1,303
Results of operations	$ (148)	$ 117	$ 29	$ (371)	$ (373)	$ (4,894)	$ (5,267)
Year Ended December 31, 2016							
Revenues and other income:							
Sales	$ 2,249	$ 42	$ 54	$ 237	$ 2,582	$ 724	$ 3,306
Transfers	—	291	—	—	291	—	291
Other income[(a)]	387	—	—	2	389	—	389
Total revenues and other income	2,636	333	54	239	3,262	724	3,986
Expenses:							
Production costs	(952)	(81)	(36)	(140)	(1,209)	(544)	(1,753)
Exploration expenses[(b)]	(306)	(1)	(6)	(10)	(323)	(7)	(330)
Depreciation, depletion and amortization[(c)]	(1,901)	(114)	(7)	(132)	(2,154)	(239)	(2,393)
Technical support and other	(21)	(4)	—	(5)	(30)	(1)	(31)
Total expenses	(3,180)	(200)	(49)	(287)	(3,716)	(791)	(4,507)
Results before income taxes	(544)	133	5	(48)	(454)	(67)	(521)
Income tax provision[(d)]	195	(26)	(2)	57	224	15	239
Results of operations	$ (349)	$ 107	$ 3	$ 9	$ (230)	$ (52)	$ (282)

(a) Includes net gain (loss) on dispositions (see Note 5) and revisions to asset retirement costs primarily due to changes in U.K. estimated costs as well as timing of abandonment activities in the U.K.

(b) Includes exploratory dry well costs, unproved property impairments, and other (see Note 11).

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

(d) Discontinued operations activity includes $135 million of deferred tax expense related to Alberta provincial corporate tax rate increase.

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:

	Year Ended December 31,		
(In millions)	2018	2017	2016
Results of operations	$ 1,503	$ (5,267)	$ (282)
Discontinued operations	—	4,894	52
Results of continuing operations	1,503	(373)	(230)
Items not included in results of oil and gas operations, net of tax:			
Marketing income and other non-oil and gas producing related activities	(170)	(107)	(39)
Income from equity method investments	214	229	142
Items not allocated to segment income, net of tax:			
Loss (gain) on asset dispositions and other income	(304)	(79)	(248)
Long-lived asset impairments	103	475	148
Unrealized loss (gain) on derivatives	(265)	81	72
Deferred tax valuation allowance increase	—	—	(32)
Segment income (loss)	$ 1,081	$ 226	$ (187)

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 liquid, and natural gas reserves.

(In millions)	U.S.	E.G.	Libya	Other Int'l	Total
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
Standardized measure of discounted future net cash flows-related to discontinued operations					$ —
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
Standardized measure of discounted future net cash flows-related to discontinued operations					$ —
Year Ended December 31, 2016					
Future cash inflows	$ 27,610	$ 1,977	$ 8,511	$ 921	$ 39,019
Future production and support costs	(12,758)	(824)	(930)	(673)	(15,185)
Future development costs	(7,233)	(13)	(296)	(1,345)	(8,887)
Future income tax expenses	—	(251)	(6,884)	514	(6,621)
Future net cash flows	$ 7,619	$ 889	$ 401	$ (583) (a)	$ 8,326
10% annual discount for timing of cash flows	(4,355)	(264)	(143)	313	(4,449)
Standardized measure of discounted future net cash flows-related to continuing operations	$ 3,264	$ 625	$ 258	$ (270)	$ 3,877
Standardized measure of discounted future net cash flows-related to discontinued operations					$ 1,076

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

Changes in the Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
(In millions)	**2018**	**2017**	**2016**
Sales and transfers of oil and gas produced, net of production and support costs	$ (4,135)	$ (2,853)	$ (1,634)
Net changes in prices and production and support costs related to future production	6,342	4,916	(3,621) [b]
Extensions, discoveries and improved recovery, less related costs	998	661	(2,174)
Development costs incurred during the period	1,240	1,027	669
Changes in estimated future development costs	(330)	183	2,534
Revisions of previous quantity estimates[a]	(501)	497	654
Net changes in purchases and sales of minerals in place	(3,035)	102	(651)
Accretion of discount	1,175	698	1,005
Net change in income taxes	4,052	(1,245)	1,038
Net change for the year	5,806	3,986	(2,180)
Beginning of the year related to continuing operations	7,863	3,877	6,057
End of the year related to continuing operations	$ 13,669	$ 7,863	$ 3,877
Net change for the year related to discontinued operations	$ —	$ —	$ 911

(a) Includes amounts resulting from changes in the timing of production.
(b) Decrease primarily due to lower realized prices.

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, 2018.

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 2018, 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 2019 Annual Meeting of Stockholders, to be filed with the SEC within 120 days of December 31, 2018 (the "2019 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 2019 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 2019 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2018 with respect to shares of Marathon Oil common stock that may be issued under our existing equity compensation plans:

- 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.
- Marathon Oil Corporation 2003 Incentive Compensation Plan (the "2003 Plan") – No additional awards will be granted under this plan.
- Deferred Compensation Plan for Non-Employee Directors – 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[c]	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by stockholders	7,650,574 [a]	$ 25.54	32,802,084 [d]
Equity compensation plans not approved by stockholders	6,979 [b]	N/A	—
Total	7,657,553	N/A	32,802,084

[a] Includes the following:

- 1,531,500 stock options outstanding under the 2016 Plan; 2,959,103 stock options outstanding under the 2012 Plan; 1,689,404 stock options outstanding under the 2007 Plan;
- 252,600 common stock units that have been credited to non-employee directors pursuant to the non-employee director deferred compensation program and the annual director stock award program established under the 2016 Plan, 2012 Plan, 2007 Plan and 2003 Plan. Common stock units credited under the 2016 Plan, 2012 Plan, 2007 Plan and 2003 Plan were 97,297, 59,251, 78,967 and 17,085, respectively;

- 1,217,967 restricted stock units granted to non-officers under the 2012 Plan and 2016 Plan and outstanding as of December 31, 2018.
- In addition to the awards reported above, 1,191,709 and 6,095,270 shares of restricted stock were issued and outstanding as of December 31, 2018, but subject to forfeiture restrictions under the 2012 and 2016 Plans, respectively.

(b) Reflects awards of common stock units made to non-employee directors under the Deferred Compensation Plan for Non-Employee Directors prior to April 30, 2003. When a non-employee director leaves the Board, he or she will be issued actual shares of Marathon Oil common stock in place of the common stock units.

(c) 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.

(d) Reflects the shares available for issuance under the 2016 Plan. No more than 14,308,395 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.

The Deferred Compensation Plan for Non-Employee Directors is our only equity compensation plan that has not been approved by our stockholders. Our authority to make equity grants under this plan was terminated effective April 30, 2003. Under the Deferred Compensation Plan for Non-Employee Directors, all non-employee directors were required to defer half of their annual retainers in the form of common stock units. On the date the retainer would have otherwise been payable to the non-employee director, we credited an unfunded bookkeeping account for each non-employee director with a number of common stock units equal to half of his or her annual retainer divided by the fair market value of our common stock on that date. The ongoing value of each common stock unit equals the market price of a share of our common stock. When the non-employee director leaves the Board, he or she is issued actual shares of our common stock equal to the number of common stock units in his or her account at that time.

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 2019 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 2019" in the 2019 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 unaudited 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 21, 2019	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 21, 2019 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/ DOUGLAS L. FOSHEE Douglas L. Foshee	Director
/s/ M.ELISE HYLAND M. Elise Hyland	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
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†	Marathon Oil Corporation 2016 Incentive Compensation Plan	DEF 14A	App. A	4/7/2016
10.8†	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
10.9†	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
10.10†	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
10.11†	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
10.12†	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
10.12†	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers	10-K	10.12	2/22/2018
10.12†	Form of Marathon Oil Corporation 2016 Incentive Compensation Plan Performance Unit Award Agreement for Officers	10-K	10.13	2/22/2018
10.15†	Marathon Oil Corporation 2012 Incentive Compensation Plan	DEF 14A	App. III	3/8/2012

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated)		
		Form	Exhibit	Filing Date
10.16†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Non-Qualified Stock Option Award Agreement	8-K	10.1	8/1/2014
10.17†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers	10-Q	10.1	5/7/2014
10.18†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Performance Unit Award Agreement for Section 16 Officers	10-Q	10.2	5/7/2014
10.19†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Initial CEO Option Grant Agreement	10-Q	10.1	11/6/2013
10.20†	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
10.21†	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
10.22†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers (3-year cliff vesting)	10-K	10.7	2/22/2013
10.23†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Restricted Stock Award Agreement for Officers (3-year cliff vesting)	10-K	10.8	2/22/2013
10.24†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Restricted Stock Award Agreement for Section 16 Officers (3-year prorata vesting)	10-K	10.9	2/22/2013
10.25†	Form of Marathon Oil Corporation 2012 Incentive Compensation Plan Restricted Stock Award Agreement for Officers (3-year prorata vesting)	10-K	10.10	2/22/2013
10.26†	Marathon Oil Corporation 2007 Incentive Compensation Plan	10-K	10.5	2/29/2012
10.27†	Form of Marathon Oil Corporation 2007 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Officers	10-K	10.6	2/29/2012
10.28†	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
10.29†	Form of Marathon Oil Corporation 2007 Incentive Compensation Plan Nonqualified Stock Option Award Agreement for Section 16 Officers	10-K	10.26	2/26/2010
10.30†	Marathon Oil Corporation 2003 Incentive Compensation Plan	10-K	10.9	2/26/2010
10.31†	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
10.32†	Marathon Oil Company Deferred Compensation Plan Amended and Restated Effective June 30, 2011	10-K	10.32	2/29/2012
10.33†	Marathon Oil Company Excess Benefit Plan Amended and Restated	10-K	10.31	2/29/2012
10.34†	Marathon Oil Corporation Officer Change in Control Severance Benefits Plan (as amended, effective January 1, 2018)	10-K	10.33	2/22/2018
10.35†	Marathon Oil Corporation Policy for Repayment of Annual Cash Bonus Amounts	10-K	10.10	2/28/2011
10.36†	Marathon Oil Corporation Executive Tax, Estate, and Financial Planning Program, Amended and Restated, Effective January 1, 2009	10-K	10.32	2/27/2009

Exhibit Number	Exhibit Description	Incorporated by Reference (File No. 001-05153, unless otherwise indicated)		
		Form	Exhibit	Filing Date
10.37	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 2017			
99.2*	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2017			
99.3	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2016	10-K	99.3	2/22/2018
99.4	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2016	10-K	99.4	2/22/2018
99.5	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2016	10-K	99.3	2/24/2017
99.6	Summary report of audits performed by Ryder Scott Company, L.P., independent petroleum engineers and geologists for 2016	10-K	99.2	2/22/2018
99.7	Summary report 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, 2018			
101.INS*	XBRL Instance Document			
101.SCH*	XBRL Taxonomy Extension Schema			
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase			
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase			
101.LAB*	XBRL Taxonomy Extension Label Linkbase			
101.DEF*	XBRL Taxonomy Extension Definition Linkbase			
*	Filed herewith.			
†	Management contract or compensatory plan or arrangement.			

Subsidiaries of Marathon Oil **Exhibit 21.1**

The names of certain subsidiaries have been omitted since, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary, as of the end of the year covered by this report, as defined under the Securities and Exchange Commission Regulation S-X 210.1-02(w).

Company Name	Country	Country Region
Alba Associates LLC	Cayman Islands	
Alba Equatorial Guinea Partnership, L.P.	United States	Delaware
Alba Plant LLC	Cayman Islands	
AMPCO Marketing, L.L.C.	United States	Michigan
AMPCO Services, L.L.C.	United States	Michigan
Atlantic Methanol Associates LLC	Cayman Islands	
Atlantic Methanol Production Company LLC	Cayman Islands	
E.G. Global LNG Services, Ltd.	United States	Delaware
Equatorial Guinea LNG Company, S.A.	Equatorial Guinea	
Equatorial Guinea LNG Holdings Limited	Bahamas	
Equatorial Guinea LNG Operations, S.A.	Equatorial Guinea	
Equatorial Guinea LNG Train 1, S.A.	Equatorial Guinea	
Marathon Delta Investment Limited	Cayman Islands	
Marathon E.G. Alba Limited	Cayman Islands	
Marathon E.G. Holding Limited	Cayman Islands	
Marathon E.G. International Limited	Cayman Islands	
Marathon E.G. Investment LLC	United States	Texas
Marathon E.G. LNG Holding Limited	Cayman Islands	
Marathon E.G. LPG Limited	Cayman Islands	
Marathon E.G. Production Limited	Cayman Islands	
Marathon International Oil Company	United States	Delaware
Marathon International Oil Holdings LLC	United States	Delaware
Marathon Malabo Holding Limited	Cayman Islands	
Marathon Offshore Alpha Limited	Cayman Islands	
Marathon Oil (East Texas) L.P.	United States	Texas
Marathon Oil (West Texas) L.P.	United States	Texas
Marathon Oil Company	United States	Ohio
Marathon Oil Corporation	United States	Delaware
Marathon Oil Dutch Holdings B.V.	Netherlands	
Marathon Oil EF LLC	United States	Delaware
Marathon Oil EF II LLC	United States	Delaware
Marathon Oil Holdings Limited	Cayman Islands	
Marathon Oil Investment LLC	United States	Delaware
Marathon Oil KDV B.V.	Netherlands	
Marathon Oil Permian LLC	United States	New Mexico
Marathon Oil U.K. LLC	United States	Delaware
Marathon Oil West of Shetlands Limited	England & Whales	
Marathon West Texas Holdings LLC	United States	Delaware
MOC Portfolio Delaware, Inc.	United States	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements listed below of Marathon Oil Corporation of our report dated February 21, 2019 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

Form S-3ASR:	Relating to:	
Reg. No	333-215733	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
Form S-8:	Relating to:	
Reg. No.	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan
	333-181301	Marathon Oil Corporation 2012 Incentive Compensation Plan
	333-211611	Marathon Oil Corporation 2016 Incentive Compensation Plan

/s/PricewaterhouseCoopers LLP
Houston, Texas
February 21, 2019

Exhibit

23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements listed below of Marathon Oil Corporation of our report dated February 22, 2018 relating to the financial statements of Alba Plant LLC, which appears as an exhibit in this Form 10-K.

Form S-3ASR:	Relating to:	
Reg. No	333-215733	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
Form S-8:	Relating to:	
Reg. No.	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan
	333-181301	Marathon Oil Corporation 2012 Incentive Compensation Plan
	333-211611	Marathon Oil Corporation 2016 Incentive Compensation Plan

/s/PricewaterhouseCoopers LLP
Houston, Texas
February 21, 2019

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references in this Annual Report on Form 10-K of Marathon Oil Corporation ("the Company"), to our summary reports on audits of the estimated quantities of certain proved reserves of oil and gas, net to the Company's interest, and to such reports and this consent being filed as exhibits to this Form 10-K. We also consent to the incorporation by reference of such reports in the Registration Statements indicated below.

Form S-3ASR:	Relating to:	
Reg. No.	333-215733	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units

Form S-8:	Relating to:	
Reg. No.	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
	333-143010	Marathon Oil Corporation 2007 Incentive Compensation Plan
	333-181301	Marathon Oil Corporation 2012 Incentive Compensation Plan
	333-211611	Marathon Oil Corporation 2016 Incentive Compensation Plan

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Registration No. F-1580

Houston, Texas
February 19, 2019

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references in this Annual Report on Form 10-K of Marathon Oil Corporation ("the Company") to our summary reports on the estimated quantities of certain proved reserves of oil and gas and to such reports and this consent being filed as exhibits to this Form 10-K. We also consent to the incorporation by reference of such reports in the Registration Statements indicated below.

Form S-3ASR:	Relating to:	
Reg. No.	333-215733	Marathon Oil Corporation Debt Securities, Common Stock, Preferred Stock, Warrants and Stock Purchase Contracts/Units
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Reg. No.	333-104910	Marathon Oil Corporation 2003 Incentive Compensation Plan
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Reg. No.	333-211611	Marathon Oil Corporation 2016 Incentive Compensation Plan

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 20, 2019

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

Exhibit 31.1

MARATHON OIL CORPORATION

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Lee M. Tillman, certify that:

1. I have reviewed this report on Form 10-K of Marathon Oil Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

/s/ Lee M. Tillman

Lee M. Tillman

Chairman, President and Chief Executive Officer

MARATHON OIL CORPORATION

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Dane E. Whitehead, certify that:

1. I have reviewed this report on Form 10-K of Marathon Oil Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2019

/s/ Dane E. Whitehead

Dane E. Whitehead

Executive Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Marathon Oil Corporation (the “Company”) on Form 10-K for the period ending December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Lee M. Tillman, Chairman, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 21, 2019

/s/ Lee M. Tillman

Lee M. Tillman
Chairman, President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Marathon Oil Corporation (the "Company") on Form 10-K for the period ending December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Dane E. Whitehead, Executive Vice President and Chief Financial Officer, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 21, 2019

/s/ Dane E. Whitehead
Dane E. Whitehead
Executive Vice President and Chief Financial Officer

Exhibit 99.1

MARATHON OIL CORPORATION

MID-CONTINENT AREA

Estimated

Future Reserves

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2017

/s/ Scott J. Wilson

Scott J. Wilson, P.E., M.B.A.
Colorado License No. 36112
Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (303) 623-4258
621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

May 24, 2018

Marathon Oil Corporation 5555 San Felipe
P.O. Box 3128
Houston, Texas 77253-3128

Gentlemen:

At the request of Marathon Oil Corporation (Marathon), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2017 prepared by Marathon's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on May 24, 2018 and presented herein, was prepared for public disclosure by Marathon in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent Marathon's estimated net reserves attributable to the leasehold interests in certain properties owned by Marathon and reviewed by Ryder Scott, as of December 31, 2017. The properties reviewed by Ryder Scott incorporate Marathon's reserve determinations and are located in the states of Montana and North Dakota.

The properties reviewed by Ryder Scott account for a portion of Marathon's total net proved reserves as of December 31, 2017. The properties reviewed by Ryder Scott and included in this letter were limited to Marathon's Mid-Continent Area assets as specified by Marathon.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Marathon, it is our opinion that the overall procedures and methodologies utilized by Marathon in preparing their estimates of the proved reserves as of December 31, 2017 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Marathon are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

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SUITE 800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799 FAX (403) 262-2790

The estimated reserves presented in this report are related to hydrocarbon prices. Marathon has informed us that in the preparation of their reserve projections, as of December 31, 2017, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Marathon attributable to Marathon's interest in properties that we reviewed are summarized below:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold Interests – Mid-Continent Assets of
Marathon Oil Corporation
As of December 31, 2017

	Proved		
	Developed Producing	Undeveloped	Total Proved
Audited by Ryder Scott			
Net Remaining Reserves			
Oil/Condensate – MBarrels	22,983	25,461	48,444
Plant Products – MBarrels	50,594	40,525	91,119
Gas – MMCF	315,969	222,324	538,293

Liquid hydrocarbons are expressed in standard 42 gallon barrels and shown herein as thousands of barrels (MBarrels). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Marathon's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods:
(1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by Marathon, for the properties that we reviewed were estimated by performance methods, analogy, or a combination of methods. Approximately 100 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through August 2017, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Marathon and were considered sufficient for the purpose thereof.

Approximately 100 percent of the proved undeveloped reserves that we reviewed were estimated by analogy.

To estimate economically recoverable proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Marathon relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Marathon for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of- the-month for each month within such period

The initial SEC hydrocarbon prices in effect on December 31, 2017 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used by Marathon for the geographic area(s) reviewed by us.

The product prices which were actually used by Marathon to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon.

The table below summarizes Marathon’s net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Marathon’s “average realized prices.” The average realized prices shown in the table below were determined from Marathon’s estimate of the total future gross revenue before production taxes for the properties reviewed by us and Marathon’s estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$51.34/Bbl	$48.50/Bbl
	NGLs	WTI Cushing	$51.34/Bbl	$23.15/Bbl
	Gas	Henry Hub	$2.98/MMBTU	$2.89/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Marathon’s individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserve estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by Marathon are based on the operating expense reports of Marathon and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. Additional gathering and transportation fees were included in the operating costs. The operating costs furnished by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Marathon are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon. The estimated net cost of abandonment after salvage was included by Marathon for properties where abandonment costs net of salvage were significant. Marathon’s estimates of the net abandonment costs were accepted without independent verification. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Marathon’s estimate.

The proved undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Marathon’s plans to develop these reserves as of December 31, 2017. The implementation of Marathon's development plans as presented to us is subject to the approval process adopted by Marathon's management. As the result of our inquiries during the course of our review, Marathon has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Marathon's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Marathon. Additionally, Marathon has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2017, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Marathon were held constant throughout the life of the properties.

Marathon's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Marathon to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Marathon. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Marathon's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Marathon's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which Marathon owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Marathon for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Marathon are responsible for the preparation of reserve estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Marathon has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Marathon's forecast of future proved production, we have relied upon data furnished by Marathon with respect to property interests owned, production from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Marathon. We consider the factual data furnished to us by Marathon to be appropriate and sufficient for the purpose of our review of Marathon's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Marathon and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Marathon, it is our opinion that the overall procedures and methodologies utilized by Marathon in preparing their estimates of the proved reserves as of December 31, 2017 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Marathon are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Marathon in their estimation of proved reserves to be effective and we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Marathon's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Marathon's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Marathon when its reserve estimates were prepared. However not withstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by Marathon.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision- making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Marathon. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Marathon.

Marathon makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Marathon has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Marathon of the references to our name as well as to the references to our third party report for Marathon, which appears in the December 31, 2017 annual report on Form 10-K of Marathon. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Marathon.

We have provided Marathon with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Marathon and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Scott J. Wilson

Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President **[SEAL]**

SJW (FWZ)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Scott James Wilson was the primary technical person responsible for the estimate of the reserves, future production, and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2000, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Atlantic Richfield Company. For more information regarding Mr. Wilson's geographic and job specific experience, please refer to the Ryder Scott Company website at https://www.ryderscott.com/company/employees/denver-employees.

Mr. Wilson earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1983 and an MBA in Finance from the University of Colorado in 1985, graduating from both with High Honors. He is a registered Professional Engineer by exam in the States of Alaska, Colorado, Texas, and Wyoming. He is also an active member of the Society of Petroleum Engineers; serving as co- Chairman of the SPE Reserves and Economics Technology Interest Group, and Gas Technology Editor for SPE's Journal of Petroleum Technology. He is a member and past chairman of the Denver section of the Society of Petroleum Evaluation Engineers. Mr. Wilson has published several technical papers, one chapter in Marine and Petroleum Geology and two in SPEE monograph 4, which was published in 2016. He is the primary inventor on four US patents and won the 2017 Reservoir Description and Dynamics award for the SPE Rocky Mountain Region.

In addition to gaining experience and competency through prior work experience, several state Boards of Professional Engineers require a minimum number of hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills as part of his registration in four states. As part of his continuing education, Mr. Wilson attends internally presented training as well as public forums relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, and Final Rule released January 14, 2009 in the Federal Register. Mr. Wilson attends additional hours of formalized external training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by: SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG) SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4- 10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals which are open at the time of the estimate, but which have not started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) 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 producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only 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.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.2

MARATHON OIL CORPORATION

BAKKEN

Estimated

Future Reserves

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2017

/s/ James L. Baird	/s/ Clark D. Parrott
James L. Baird, P.E.	Clark D. Parrott, P.E.
Colorado License No. 41521	Colorado License No. 35262
Managing Senior Vice President	Senior Petroleum Engineer

[SEAL] **[SEAL]**

RYDER SCOTT COMPANY, LP.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
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May 1, 2018

Marathon Oil Corporation 5555 San Felipe
P.O. Box 3128
Houston, Texas 77253-3128

Gentlemen:

At the request of Marathon Oil Corporation (Marathon) , Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2017 prepared by Marathon's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on May 1, 2018 and presented herein, was prepared for public disclosure by Marathon in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations . The estimated reserves shown herein represent Marathon's estimated net reserves attributable to the leasehold interests in certain properties owned by Marathon and reviewed by Ryder Scott, as of December 31, 2017. The properties reviewed by Ryder Scott incorporate Marathon reserve determinations and are located in the states of Montana and North Dakota.

The properties reviewed by Ryder Scott account for a portion of Marathon's total net proved reserves as of December 31, 2017. The properties reviewed by Ryder Scott and included in this letter were limited to Marathon's Bakken assets as specified by Marathon.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities and/or Reserves Information ." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Marathon, it is our opinion that the overall procedures and methodologies utilized by Marathon in preparing their estimates of the proved reserves as of December 31, 2017 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Marathon are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards .

The estimated reserves presented in this report are related to hydrocarbon prices. Marathon has informed us that in the preparation of their reserve projections , as of December 31, 2017, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Marathon attributable to Marathon's interest in properties that we reviewed are summarized below:

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold Interests - Bakken Assets of
Marathon Oil Corporation

As of December 31, 2017

	Proved		
	Developed Producing	Undeveloped	Total Proved
Audited by Ryder Scott			
Net Reserves			
Oil/Condensate – MBarrels	114,906	160,615	275,521
Plant Products – MBarrels	18,047	25,741	43,788
Gas – MMCF	75,202	117,709	192,911

Liquid hydrocarbons are expressed in standard 42 gallon barrels and shown herein as thousands of barrels (MBarrels). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Marathon's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by Marathon, for the properties that we reviewed were estimated by performance methods, analogy, or a combination of methods. Approximately 100 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through August 2017, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Marathon and were considered sufficient for the purpose thereof.

Approximately 100 percent of the proved undeveloped reserves that we reviewed were estimated by analogy.

To estimate economically recoverable proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Marathon relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by Marathon for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of- the-month for each month within such period..

The initial SEC hydrocarbon prices in effect on December 31, 2017 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used by Marathon for the geographic area reviewed by us.

The product prices which were actually used by Marathon to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used by

Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon.

The table below summarizes Marathon's net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Marathon's "average realized prices." The average realized prices shown in the table below were determined from the estimate of the total future gross revenue before production taxes for the properties reviewed by us and the estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$51.34/Bbl	$48.78/Bbl
	NGLs	WTI Cushing	$51.34/Bbl	$16.20/Bbl
	Gas	Henry Hub	$2.98/MMBTU	$2.29/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Marathon's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserve estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by Marathon are based on the operating expense reports of Marathon and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. Additional gathering and transportation fees were included in the operating costs. The operating costs furnished by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Marathon are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Marathon were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Marathon. The estimated net cost of abandonment after salvage was included by Marathon for properties where abandonment costs net of salvage were significant. Marathon's estimates of the net abandonment costs were accepted without independent verification. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Marathon's estimate.

The proved undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Marathon's plans to develop these reserves as of December 31, 2017. The implementation of Marathon's development plans as presented to us is subject to the approval process adopted by Marathon's management. As the result of our inquiries during the course of our review, Marathon has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Marathon's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Marathon. Additionally, Marathon has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2017, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Marathon were held constant throughout the life of the properties.

Marathon's forecasts of future production rates are based on historical performance from wells currently on production.

Test data and other related information were used by Marathon to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Marathon. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Marathon's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Marathon's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a review of the properties in which Marathon owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Marathon for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Marathon are responsible for the preparation of reserve estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Marathon has informed us that they have furnished us all of the material accounts, records, engineering data, and reports and other data required for this investigation. In performing our audit of Marathon's forecast of future proved production, we have relied upon data furnished by Marathon with respect to property interests owned, production from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Marathon. We consider the factual data furnished to us by Marathon to be appropriate and sufficient for the purpose of our review of Marathon's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Marathon and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Marathon, it is our opinion that the overall procedures and methodologies utilized by Marathon in preparing their estimates of the proved reserves as of December 31, 2017 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Marathon are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Marathon in their estimation of proved reserves to be effective and we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Marathon's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Marathon's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Marathon when its reserve estimates were prepared. However not withstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by Marathon.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Marathon. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Marathon.

Marathon makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Marathon has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of Marathon of the references to our name as well as to the references to our third party report for Marathon, which appears in the December 31, 2017 annual report on Form 10-K of Marathon. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Marathon.

We have provided Marathon with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Marathon and the original signed report letter, the original signed report letter shall control and supersede the digital version.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, LP.
TBPE Firm Registration No. F-1580

/s/ James L. Baird

James L. Baird, P.E.
Colorado License No.
41521
Managing Senior Vice President **[SEAL]**

/s/ Clark D. Parrott

Clark D. Parrott, P.E.
Colorado License No. 35262
Senior Petroleum Engineer **[SEAL]**

JLB-CDP (FWZ)/pls

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. James Larry Baird was the primary technical person responsible for overseeing the estimate of the reserves.

Mr. Baird, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President and also serves as Manager of the Denver office, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Baird served in a number of engineering positions with Gulf Oil Corporation (1970-1973), Northern Natural Gas (1973-1975) and Questar Exploration & Production (1975-2006). For more information regarding Mr. Baird's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Baird earned a Bachelor of Science degree in Petroleum Engineering from the University of Missouri at Rolla in 1970. He is a registered Professional Engineer in the States of Colorado and Utah. He is also a Legion of Honor member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, several State Boards of Professional Engineers require a minimum number of hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Baird fulfills as part of his registration in two states. As part of his continuing education, Mr. Baird attends internally presented training as well as public forums relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, and Final Rule released January 14, 2009 in the Federal Register. Mr. Baird attends additional hours of formalized internal and external training covering such topics as the SPENVPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering and petroleum economics evaluation methods, various analysis software and ethics for consultants.

Based on his educational background, professional training and more than 48 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Baird has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a *given date, by application of development projects to known accumulations.* All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (Ie., absence of reservoir, structurally low reservoir, or negative test results}. Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations}.

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, 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.*

(i} The area of the reservoir considered as proved includes:

(A} The area identified by drilling and limited by fluid contacts, if any, and

(B} Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES {SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a *well penetration unless geoscience engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.*

/

(iii) Where direct observation from well penetrations has defined a *highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.*

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a *pilot project in an area of the reservoir with properties no more favorable than in the reservoir* as a *whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10{a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE) WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG) SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate, but which have not started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i)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 producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only 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.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.9

Alba Plant LLC

Financial Statements

December 31, 2018, 2017 and 2016

Alba Plant LLC
Index
December 31, 2018, 2017 and 2016

Independent Auditor’s Report

To the Management of Alba Plant LLC:

We have audited the accompanying financial statements of Alba Plant LLC, which comprise the balance sheet as of December 31, 2017, and the related statements of income, stockholders’ equity, and cash flows for each of the two years in the period ended December 31, 2017.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors’ Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position at December 31, 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of matter

As discussed in Note 6 to the financial statements, the Company has entered into significant transactions with certain related parties. Our opinion is not modified with respect to this matter.

Other Matter

The accompanying balance sheet of Alba Plant LLC as of December 31, 2018, and the related statements of income, stockholders' equity and cash flows for the year then ended are presented for purposes of complying with Rule 3-09 of SEC Regulation S-X; however, Rule 3-09 does not require the 2018 financial statements to be audited and they were not audited, reviewed, or compiled by us and, accordingly, we do not express an opinion or any other form of assurance on them.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 22, 2018

Alba Plant LLC
Balance Sheets
December 31, 2018 and 2017

(in thousands of dollars)	Unaudited 2018	2017
Assets		
Cash and cash equivalents	$ 87,080	$ 142,449
Accounts receivable	21,669	29,607
Accounts receivable–related parties	10,565	14,731
Inventory	35,674	37,693
Total current assets	154,988	224,480
Facility cost	568,634	567,667
Less: Accumulated depreciation	347,660	335,096
Net facility cost	220,974	232,571
Total assets	$ 375,962	$ 457,051
Liabilities and Stockholders' Equity		
Accounts payable and accrued liabilities–related parties	7,471	7,053
Accrued government royalty–net profit interest	28,118	28,377
Foreign income taxes payable	83,923	74,322
Total current liabilities	119,512	109,752
Net deferred tax liability	45,106	46,845
Stockholders' equity		
Common stock - 1,000 shares issued and outstanding (par value $1.00 per share, 50,000 shares authorized)	1	1
Retained earnings	211,343	300,453
Total stockholders' equity	211,344	300,454
Total liabilities and stockholders' equity	$ 375,962	$ 457,051

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

Alba Plant LLC

Statements of Income

Years Ended December 31, 2018 and 2017

(in thousands of dollars)	Unaudited 2018	2017	2016
Revenues			
Plant products	$ 295,357	$ 298,923	$ 186,754
Plant products–related parties	933	799	931
Condensate–related parties	140,707	131,923	102,687
Other income	837	962	850
Other income–related parties	248	286	271
Total revenues	438,082	432,893	291,493
Expenses			
Direct operating–related parties	35,541	37,331	47,929
Depreciation and amortization	12,564	11,233	26,555
General and administrative–related parties	30,059	28,165	28,770
Government royalty–net profit interest	28,117	28,380	17,536
Shipping and handling–related parties	4,898	3,543	4,088
Total expenses	111,179	108,652	124,878
Income from operations	326,903	324,241	166,615
Interest income	996	227	0
Income before income taxes	327,899	324,468	166,615
Income tax expense	82,009	81,152	41,637
Net income	$ 245,890	$ 243,316	$ 124,978

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

Alba Plant LLC

Statements of Stockholders' Equity

Years Ended December 31, 2018 and 2017

(in thousands of dollars)	Common Stock Shares	Common Stock Amount	Retained Earnings	Total Stockholders' Equity
Balances at December 31, 2015	1	$ 1	$ 316,159	$ 316,160
Net income			124,978	124,978
Dividends			(142,000)	(142,000)
Balances at December 31, 2016	1	$ 1	$ 299,137	$ 299,138
Net income			243,316	243,316
Dividends			(242,000)	(242,000)
Balances at December 31, 2017	1	$ 1	$ 300,453	$ 300,454
Net income			245,890	245,890
Dividends			(335,000)	(335,000)
Balances at December 31, 2018 (unaudited)	1	$ 1	$ 211,343	$ 211,344

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

Alba Plant LLC
Statements of Cash Flows
Years Ended December 31, 2018 and 2017

(in thousands of dollars)	Unaudited 2018	2017	2016
Operating activities			
Net income	$ 245,890	$ 243,316	$ 124,978
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	12,564	11,233	26,555
Deferred income tax	(1,739)	6,827	5,723
Changes in:			
Accounts receivable and accounts receivable-related parties	12,104	(2,968)	(16,518)
Prepayments	—	—	1,299
Inventory	2,019	(656)	5,883
Accounts payable and accrued liabilities-related parties	221	75	(5,668)
Accrued government royalty–net profit interest	(260)	10,841	804
Foreign income taxes payable	9,601	38,387	6,618
Net cash provided by operating activities	280,400	307,055	149,674
Investing activities			
Capital expenditures	(769)	(65)	(120)
Net cash used in investing activities	(769)	(65)	(120)
Financing activities			
Dividends	(335,000)	(242,000)	(142,000)
Net cash used in financing activities	(335,000)	(242,000)	(142,000)
Net increase (decrease) in cash and cash equivalents	(55,369)	64,990	7,554
Cash and cash equivalents at beginning of period	$ 142,449	$ 77,459	$ 69,905
Cash and cash equivalents at end of period	$ 87,080	$ 142,449	$ 77,459
Supplemental disclosure			
Income taxes paid	$ 74,146	$ 35,939	$ 29,296
Change in capital expenditure accrual	$ 198	$ (13)	$ (79)

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

1. Organization and Nature of Business

Alba Plant LLC (the “Company”) is an exempted limited liability company organized under the laws of the Cayman Islands. The purposes of the Company are (i) to construct, own, operate and maintain the Alba Liquefied Petroleum Gas Plant (“the plant”); (ii) to further process the natural gas produced under the Alba Production Sharing Contract (“Alba PSC”); (iii) to recover additional condensate; (iv) to separate butane and propane from the natural gas and process them into gas liquids; (v) to store the liquid hydrocarbons processed; (vi) to sell all liquid hydrocarbons produced by the plant; and (vii) to finance such activities on terms the Company determines to be appropriate. The Company commenced commercial operations in January 1997. Sociedad Nacional de Gas de Guinea Ecuatorial (“Sonagas”) has a 20% ownership in the Company with the remaining 80% owned by Alba Associates LLC. The ownership interest in Alba Associates LLC is as follows as of December 31, 2018, 2017 and 2016:

Samedan of North Africa, Inc. ("Samedan")	34.79166%
Marathon E.G. LPG Limited ("EG LPG")	23.45834
Marathon E.G. Alba Limited ("EG Alba")	19.08334
Marathon E.G. Production Limited ("MEGPL")	11.45833
Marathon E.G. Offshore Limited ("EG Offshore")	11.20833
	100.00000%

The Equatorial Guinea Government is entitled to a 10% interest in the Company’s annual net profit, as defined in the Processing and Marketing Agreement (“PMA”) between The Republic of Equatorial Guinea and the Company dated January 22, 1996.

The Company has no employees, and as such has entered into an agreement with MEGPL to provide certain operating, general and administrative services on behalf of the Company (Note 6).

2. Summary of Significant Accounting Policies

Basis of Presentation

These financial statements, including notes have been prepared in accordance with U.S. generally accepted accounting principles. The December 31, 2018 financial statements, including notes are presented as unaudited.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 financial statements and the reported amounts of revenue and expenses during the respective reporting periods. Actual results could differ from those estimates.

Foreign Currency Transactions

The functional currency applicable to the Company is the U.S dollar. Current assets and current liabilities denominated in other currencies are converted into U.S. dollars at the applicable rate on the balance sheet date, and the resulting unrealized foreign exchange gains and losses are recorded in the statement of income.

Cash and Cash Equivalents

Includes cash on hand and highly liquid investments with original maturities of three months or less.

Receivables less Allowance for Doubtful Accounts

Receivables recorded in the financial statements represent bona fide claims against debtors, or other charges arising on or before the balance sheet date. All receivables have been appropriately reduced to their estimated net realizable value. All receivables are recorded at the invoiced amounts and do not bear interest. An allowance for receivables is created with a charge directly to bad debt expense when it becomes probable the receivables will not be collected. No allowance has been recorded as of December 31, 2018 and December 31, 2017.

Inventory

Materials and supplies inventory is valued at weighted average cost and reviewed periodically for obsolescence or impairment when market conditions indicate. Condensate, propane, and butane inventories are recorded at weighted average cost and carried at the lower of cost or net realizable value.

Facility Cost

Facility cost represents the cost of the plant including related extraction components, piping and other equipment, and includes the cost of related engineering and design services and installation materials and labor. Facility costs are primarily depreciated on a straight-line basis. In 2016, the anticipated commercial life of the Alba PSC was extended as a result of the installation of a new compression platform. Accordingly, the Company extended the estimated remaining life of the plant for depreciation purposes from 2026 to 2034.

Maintenance and repairs are charged to expense as incurred. Renewals, betterments and major repairs that materially extend the life of the plant are capitalized.

We evaluate the plant including related extraction components, piping and other equipment, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be fully recoverable. If the value from the use of the asset and its eventual disposition is anticipated to be less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Assets 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.

Under the provisions of the PMA, the Company is not legally obligated to dismantle the plant and restore the Alba site, and as such, no asset retirement obligation has been recorded for these facilities.

Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include the Company's expectation to generate sufficient future taxable income including tax credits, and operating loss carryforwards. Valuation allowances are recorded against a deferred tax asset when it is more likely than not that the deferred tax asset will not be realized. 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.

Revenue Recognition

Revenues are recognized when title is transferred to customers, the sales price is fixed or determinable, and collectability is reasonably assured. Costs associated with revenues are recorded in direct operating costs.

Concentration of Credit Risk

During 2018, substantially all of the LPG products were sold to two third-party purchasers, Vitol S.A. and Philia Trading Pte. Ltd. During 2017 and 2016, substantially all of the LPG products were sold to an individual third-party purchaser. Additionally, all of the condensate was sold to a related party. This concentration of customers may impact the Company's credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions.

3. Accounting Standards

Not Yet Adopted

Revenue recognition standard

In May 2014 and August 2015, the FASB issued an update that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. Among other things, the standard requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. We will adopt this standard in 2019. Upon adoption the standard shall be applied retrospectively to each prior reporting period presented ("full retrospective method") or with the cumulative effect of initially applying the update recognized at the date of initial application ("modified retrospective method"). We plan to adopt this new standard using the modified retrospective method. We continue to assess our contracts that will be subject to this standard and the impact it will have on our results of operations, financial position or cash flows. We plan to provide the disclosures required by this standard, such as key sources of revenues from transactions with customers, disaggregated revenue information, and significant accounting estimates and judgments, upon adoption.

Lease accounting standard

In February 2016, the FASB issued a new lease accounting standard, which requires lessees to recognize most leases, including operating leases, on the balance sheet as a right of use asset and lease liability. Short-term leases can continue being accounted for off balance sheet based on a policy election. This standard 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. This standard is effective for us in the first quarter of 2020 and shall be applied using a modified retrospective approach at the beginning of the earliest period presented in the financial statements. Early adoption is permitted. We will apply practical expedients provided in the standard that allow, amongst others, not to reassess contracts that commenced or expired prior to the effective date. We will elect a policy not to recognize right of use assets and lease liabilities related to short-term leases.

In July 2018, the FASB issued a new transition option that allows entities to adopt the new lease accounting standard using the modified retrospective transition method by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption rather than in the earliest period presented. We will elect this new transition option and continue to apply the legacy guidance in ASC 840, Leases, including its disclosure requirements, in the comparative periods presented in the year of adoption.

We continue to evaluate our contracts and are gathering the necessary data to determine the financial impact of this standard on our consolidated financial statements and related disclosures. While we have yet to finalize the estimated impact of this standard will have on our consolidated financial statements, the adoption is anticipated to result in an increase in both assets and liabilities related to our leases.

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 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. Early adoption is permitted starting January 2019. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our results of operations, financial position or cash flows.

Recently Adopted

Classification in the statement of cash flows

In August 2016, the FASB issued a new accounting standards update which seeks to reduce the existing diversity in practice in how certain transactions are classified in the statement of cash flows. We adopted this standard in 2018 on a retrospective basis with no significant impact on our results of operations, financial position or cash flows.

4. Inventory

Inventory as of December 31, 2018 and 2017 is summarized as follows:

(in thousands of dollars)	Unaudited 2018	2017
Materials and supplies	$ 35,230	$ 37,074
Liquid hydrocarbon products	444	619
	$ 35,674	$ 37,693

5. Income Taxes

For income tax purposes, Alba Plant LLC is treated as a local corporation and is only subject to local income taxes in accordance with the PMA between The Republic of Equatorial Guinea and Alba Plant LLC dated January 22, 1996. The Company's effective tax rate for 2018, 2017 and 2016 was 25%. Income before income taxes for Alba Plant LLC was $327,899, $324,468 and $166,615 for 2018, 2017 and 2016 respectively.

The provision for income tax expense comprises:

(in thousands of dollars)	Unaudited 2018	2017	2016
Current tax expense	$ 83,748	$ 74,325	$ 35,914
Deferred tax expense (benefit)	(1,739)	6,827	5,723
	$ 82,009	$ 81,152	$ 41,637

The deferred tax assets and deferred tax liability resulted from the following:

(in thousands of dollars)	Unaudited 2018	2017
Deferred tax assets		
Government royalty - net profit interest	$ 7,030	$ 7,094
	$ 7,030	$ 7,094
Deferred tax liability		
Facility cost	$ 52,136	$ 53,939
	$ 52,136	$ 53,939
Net deferred tax liabilities	$ 45,106	$ 46,845

As of December 31, 2018 our income tax returns for Equatorial Guinea remain subject to examination for the tax years 2007-2017. As of December 31, 2018, 2017 and 2016 there are no uncertain tax positions.

6. Related Party Transactions

Related parties include:

- Alba Associates LLC and Sonagas, the Company's owners;
- Samedan, EG LPG, EG Alba, MEGPL, and EG Offshore, the owners in Alba Associates LLC; and
- Marathon Oil Marketing, Ltd. ("MOM"), Marathon International Oil (G.B.) Limited ("MIOGB"), Equatorial Guinea LNG Train1, S.A. ("EG LNG") and other affiliates of Marathon Oil Corporation ("Marathon"), which is one of the ultimate owners of Alba Associates LLC.

The Company enters into certain sales and purchases and has certain accounts receivable and accounts payable with related parties arising in the normal course of business. Accounts receivable, less allowance for doubtful accounts and accounts payable associated with related parties at December 31, 2018 and 2017, consist of the following:

	Unaudited			
	2018		2017	
(in thousands of dollars)	Receivable from	Payable to	Receivable from	Payable to
Sonagas	$ 1,052	$ —	$ 1,538	$ —
MOM	9,472	—	13,174	10
MIOGB	—	—	—	4
MEGPL	17	7,434	17	7,026
Marathon	24	37	2	13
	$ 10,565	$ 7,471	$ 14,731	$ 7,053

Plant products-related parties revenue for the years ended December 31, 2018 and 2017, relate to LPG sold to Sonagas, and propane sold to EG LNG.

Condensate-related parties revenue for the years ended December 31, 2018 and 2017, relates to sales of condensate to MIOSCO (GB) and MOM.

Other income-related parties for the years ended December 31, 2018 and 2017, relates to terminal fees on condensate sold to MIOSCO (GB) and MOM.

The Company purchases its feed gas from gas produced under the Alba PSC at a rate of $0.25/mmbtu as specified in the PMA. MEGPL, the operator of Alba PSC, collects the funds related to the feed gas sales.

Direct operating expenses-related parties for the years ended December 31, 2018, 2017 and 2016, were costs incurred by MEGPL for the operation of the plant and billed to the Company in accordance with the Technical and Administrative Services Agreement. This agreement is effective through 120 days after processing activities have terminated, as defined by the agreement. Additionally, the Company has agreed to pay an overhead fee to MEGPL equal to 1% of all cost incurred in support of plant operations.

Shipping and handling services, and general and administrative services are provided primarily by MEGPL. These services are charged to the Company at cost.

7. Fair Value of Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, receivables and short-term payables. The carrying amounts approximate fair market value due to the highly liquid nature of the short-term instruments.

8. Dividends

In accordance with the Alba Plant Members' Agreement, all available funds, as defined in the agreement, are distributed to the Company's owners on the basis of their respective ownership. Dividends distributed in 2018, 2017 and 2016 were $335 million, $242 million and $142 million, respectively. Dividends per share in 2018, 2017 and 2016 were $335 thousand, $242 thousand and $142 thousand, respectively.

9. Contingencies

Various local laws and regulations affect the Company's operations and costs. Management believes that the Company is in substantial compliance with all applicable local laws and regulations and that the ultimate resolution of any claims or legal proceedings, if any, instituted against the Company will not have a material effect on its financial position, results of operations, or cash flows.

10. Subsequent Events

Events and transactions subsequent to the balance sheet date have been evaluated through February 21, 2019, the date these financial statements were issued, for potential recognition or disclosure in the financial statements.